THE 1970 NATIONAL POWER SURVEY

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PART III

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GUIDELINES FOR GROWTH OF THE ELECTRIC POWER INDUSTRY

THE 1970 NATIONAL POWER SURVEY

FEDERAL POWER COMMISSION

PART III

ADVISORY REPORTS TO THE FEDERAL POWER COMMISSION
PREPARED BY

THE SOUTH CENTRAL REGIONAL ADVISORY COMMITTEE

THE WEST CENTRAL REGIONAL ADVISORY COMMITTEE

THE WEST REGIONAL ADVISORY COMMITTEE

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FOREWORD

In January 1966, the Federal Power Commission established six Regional Advisory Committees to assist the Commission in updating the National Power Survey through the development of individual regional reports.

The reports of the Regional Advisory Committees are being distributed by the Commission in advance of completing the full survey in order to make the useful information which they contain immediately available to interested reviewers. The Commission anticipates that the full survey, which will consist of the Commission's report and the reports of all Regional and Technical Advisory Committees, will be published in 1970.

As in all Commission Advisory Committee activities, the Commission's staff has participated in the deliberations of the Committees. While consultation and suggestions have been freely exchanged by the Committees and staff, the final reports are the products of the Committees.

We gratefully acknowledge the participation of the members of the Regional Advisory Committees and the many others who assisted them in these studies. Memberships of the individual Regional Advisory Committees are shown in the corresponding report sections of this volume.

The Federal Power Commission

PART III

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ELECTRIC POWER IN THE SOUTH CENTRAL REGION

1970 - 1980 - 1990

A REPORT
TO THE FEDERAL POWER COMMISSION

PREPARED BY
THE SOUTH CENTRAL REGIONAL ADVISORY COMMITTEE

FEBRUARY 1969

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INTRODUCTION

In 1964 the Federal Power Commission published the National Power Survey based on studies carried out by its staff with assistance from industry advisory committees. The electric utility industry is rapidly changing and is being confronted with new problems and responsibilities. This prompted the Federal Power Commission to make plans to update the National Power Survey. To assist in such work, the Commission in its revised Order dated January 10, 1966, appointed six regional advisory committees. Certain general instructions were given to these committees by FPC and the committees were to prepare a report covering the work they accomplished.

The South Central Regional Advisory Committee, with the assistance of the staff of the Fort Worth Regional Office of the Federal Power Commission, has prepared its report. Members of this committee are listed in the Acknowledgments section of this report.

This report sets forth certain statistical data and also information covering operating practices of individual systems and the coordination which has been achieved between systems, as well as projecting the availability of resources, the growth and future plans of all segments of the electric utility industry in this region through the year 1990.

Information, data, projections and future plans of the power industry were developed by the following Task Forces of the South Central Regional Advisory Committee:

Load Forecasting
Fossil Fuels Resources
Coordinated Planning and Development
General Patterns of Generation and Transmission

This report is made up of the individual reports of these various Task Forces.

The reports of these several Task Forces will indicate that the electric utility companies of the South Central Region have been meeting their obligations to furnish adequate and dependable electric service and have had an excellent record of service reliability. It also discloses that there have been coordinated groups planning and operating together over a period of years to bolster the reliability of individual systems; and in addition, adequate individual company and joint coordinated plans between systems are being currently made and kept up-to-date to adequately meet all the future power requirements in the South Central Region, and to cooperate with adjacent areas in planning and coordination.

It is hoped that the report will be useful to the Executive Advisory Committee in its work and to the Federal Power Commission staff in updating the National Power Survey.

SUMMARY

Forecast of Power Requirements for the South Central Region 1970–1990

The population of the South Central Region was 23,238,000 in 1966 and, based on Census projections, should increase to 33,060,000 by 1990. Except for electrical energy trends, population is the principal guide used in the electric load growth forecast.

The compound annual rates of growth for the peak demand in the South Central Region for the three 5-year periods from 1950 to 1965 have been 13.1, 10.0, and 9.1 percent. This growth rate is projected between 1965 and 1970 to average 10.3 percent based on utility load estimates and taking into consideration that 1965 was an unusually cool summer. The compound rate of growth is gradually reduced to a figure of 6.9 percent between 1985 and 1990, as shown on Figure 2. The coincident peak demands for the South Central Region in 1965 and 1966 were 24,589 mw and 27,440 mw. The coincident peak is expected to reach 181,811 mw in 1990. Figure 4 readily shows this potential growth.

The energy requirements in 1965 and 1966 were 118,641 million kwh and 131,565 million kwh, respectively. The projected energy requirements in 1990 are estimated to be 900,380 million kwh. Air conditioning, winter heating loads, and electric utility promotional programs affect annual load factors and cause variations in rates of growth.

After the approval of the load forecast by the regional committee, a major utility in Power Supply Area 35 requested a higher estimate in 1990. This higher estimate is reflected by footnotes in tabular load data in this report, and sufficient capacity to meet this load, plus reserve requirements, is provided in the power requirements and supply analyses.

It should be noted that the non-farm residential energy usage per customer for the South Central Region averaged 5,310 kwh per customer in 1966 and is predicted to reach 18,510 kwh per customer in 1990. Commercial energy use per customer during the same period is expected to increase from 30,063 kwh to 99,630 kwh. Industrial energy use is by far the largest category of classified sales and in 1966 represented 51,039 million kwh energy requirements and is predicted to reach 418,963 million kwh in 1990, or 46.5 per cent of the total regional requirements.

In conclusion, the load forecast establishes projected load levels at 5-year intervals to 1990. These forecasts make provisions for new energy uses but do not predict recessions. These load forecasts should be used with the thought that these load levels could be reached a little earlier than the years shown or, under certain conditions, the levels might be reached after the years indicated. These load forecasts provide the basis for developing projected patterns of generation and transmission facilities in the South Central Region.

Fuels Resources for the South Central Region

A questionnaire submitted to the 33 major utilities in the South Central Region provided the largest portion of the data on fossil fuels resources. Based on current technology and projected costs and excluding hydroelectric generation, the year 1966 indicated about 95 percent generation from natural gas and about 5 percent from coal in the South Central Region. By 1990, the fuel forecast for total thermal generation is about 46 percent natural gas, 43 percent nuclear fuels, and 10 percent coal. The ultimate development will depend on the competitive race between suppliers of nuclear fuels and coal. As the prices of gas increase to a point where conversion to coal is considered, oil usage for fuel may show development due to the inexpensive conversion factor from gas to oil.

The survey also indicated that although natural gas reserves in the South Central Region are increasing, the rate of increase will not be sufficient to continue supplying all industrial establishments in the Region in addition to the amount required for export to other parts of the United States during the next 25 years.

The break-even point between existing fuels and nuclear fuels is widely divergent and some systems projected new installations after 1975 for all nuclear

and others for all coal. Other systems projected installation of nuclear plants early in the period under consideration followed by the installation of coal-fired units, in order to obtain a mix of base load capability and peaking capability.

Pumped-storage hydroelectric projects and gas turbines are expected to be used for peaking capacity where economically feasible when the base load nuclear plants are used extensively throughout the South Central Region.

For plants located near major load centers, the "unit train" deliveries of coal will probably prove most economical—especially in Oklahoma, Kansas and Arkansas.

Movement of barges along the Mississippi River, Gulf Intracoastal Waterway, and the navigable Arkansas River will allow coal purchases from western Kentucky fields to be transported to the states of Missouri, Mississippi, Arkansas, Louisiana and Texas.

The survey indicated research activity in the South Central Region in the nuclear field, as evidenced by experimental projects being conducted—the SEFOR Project in northwest Arkansas, the Texas Atomic Energy Research Foundation Program, the Westinghouse liquid metal fast-breeder reactor program, and the Gulf General Atomic Project on gas-cooled fast-breeder reactor power plant.

Air pollution is not considered a major problem in the South Central Region due to the preponderant use of natural gas in the generation of power. It may become a factor in the future when it becomes necessary to use other types of fuels for generation.

Recommendations for Coordinated Planning and Development

The principles and practices outlined in Chapter 3 relate to the interconnected systems of the electric utilities of the region responsible for providing reliable electric power service in those areas where each system holds itself ready, able, and willing to provide such service. Each individual system has the responsibility to (a) provide enough power and energy to supply its customers' requirements, and (b) to provide transmission facilities adequate to furnish the electrical requirements of its customers at system load centers. Usually, individual systems can discharge their basic power supply responsibilities more efficiently through participation in coordinated planning. It is believed that such coordination should be concerned with: first, the elimination of any possibility of cascading or propagating outages; and secondly, with any advantages that result through the coordinated planning of joint power supply.

The number of electric utilities participating in coordination should be kept to a manageable size to permit effective communication and cooperation among all its members. The geographical area of coordination should be limited in extent so that adequate transmission ties and associated equipment may be constructed in such a way as to permit reliable and economical flow of electric energy throughout the coordinated area. Coordination of planning, development, and operation of electric systems should be carried out by those interconnected electric utilities whose planning and operation of generation and transmission facilities have a major effect on the reliability of bulk power supply in the area. Any system that purchases its power supply, or a major part of its power supply, may participate in area coordination through the agency of the system that directly or indirectly furnishes its power supply.

About 95 percent of the generating capacity in the region is interconnected under agreements that individually define the degree of coordination between the systems, and under which the benefits of advancing technology are shared by all the customers.

Much emphasis has been placed on the reliability of bulk power supply and on the prevention of power failures that might affect large areas of the United States. Much of this emphasis stems from the Federal Power Commission report on the Northeast Power Failure of November 9–10, 1965. Future coordination requirements must consider the advantages and disadvantages of interconnected and synchronous operation over large areas. The coordinated groups comprising the FPC South Central Region have planned capacity and transmission line additions, so the various groups of systems are self-sufficient and have a reliable power supply whether or not they operate in synchronism with a larger group. In planning for future coordination in the area, the major systems will be interdependent on other systems within subareas of the region but capable of providing reliable electric service when the region is separated from other regions.

General Patterns of Generation and Transmission 1970–1990

Load patterns in the South Central Region indicate a regional load growth greater than the average for the nation. The region has a predominant summer peak, the winter peak being approximately 70 percent of the annual summer peak. This difference in seasonal peaks provides a basis for the present seasonal diversity exchange of some 1,500 megawatts between eleven of the companies in the region and the Tennessee Valley Authority directly east of this region.

Generation locations for the period of the study beyond four or five years in the future are general locations. They are usually located in the proximity of major load centers in the region. The average capacity of plants increases from 900 megawatts to 4,000 megawatts during the period 1970–1990, an increase of over 300 percent. During the same period, the average of the maximum unit sizes increases from 500 megawatts to 1,400 megawatts, an increase of nearly 200 percent.

Water supply for cooling purposes becomes an increasing problem over the period of the study. Although there are many uncertainties involved in the water quality criteria of the several states and the Federal government, it is not expected that water supply will be extremely critical in the area.

Hydro capacity represents about 5 percent of the peak load in 1970. Additions projected beyond 1970 are for the most part pumped-storage projects. Due to (1) the close economic feasibility of pumped-storage peaking units as compared to other types of peaking generation, (2) the long-hour use during heat storms, and (3) the lack of congressional approval of federal construction of off-stream storage projects, the amount of hydro capacity projected beyond 1970 is probably in excess of that which will be installed. Nevertheless, if all hydro which has been projected should be installed, the percentage of hydro capacity to peak load in 1990 is less than 5 percent.

Transmission patterns indicate a continuation of the EHV line development started in the early 1960's. By 1990, a comprehensive 345-kv and 500-kv transmission network is projected. In addition, the beginning of 750-kv transmission is developing in Oklahoma. The projected network provides stronger interconnection between the operating utilities within the region and with adjoining regions to the end that reliability of service will be improved.

CHAPTER 1

FORECAST OF POWER REQUIREMENTS FOR THE SOUTH CENTRAL REGION 1970–1990

Introduction

The Fort Worth Regional Office of the Federal Power Commission prepared a load forecast to 1990 and submitted it to the Task Force of Load Forecasting for review. As a result of this review the further discussions by the South Central Regional Advisory Committee (SCRAC), the load forecasts were adjusted to a higher level. These higher estimates were approved by the SCRAC on April 25, 1967.

In using these load forecasts, it should be understood that some of the power supply area forecasts are not as high as the current forecasts by some of the electric utilities in the area. In other power supply areas, the forecasts of various utilities are lower than this load forecast. These differences stem from degrees of optimism and may reflect variations in load forecasting techniques or other factors as indicated by a particular utility's comments given in Appendix C. Some systems and groups use a constant percentage annual rate of growth as far into the future as 1990. The load forecasts in this report are based on a gradually decreasing percentage annual rate of growth but at the same time reflect an increasing annual incremental growth. (See Figures 3 and 5.)

The tabular data in this report is generally similar to data published in Advisory Committee Report No. 13 in Part II of the first National Power Survey issued in 1964; however, much more detailed information is provided in this report, which covers only the South Central Region of the United States and is comprised of Power Supply Areas 25, 29, 33, 34, 35, 37, 38 and that part of 17–F in Kansas and Missouri.

The forecast provides a base for the fuel survey in Chapter 2 and furnished load levels used for the Task Force of General Patterns of Generation and Transmission. It was also used for reference by the Task Force of Coordinated Planning and Development and by their work group on Hydroelectric Utilization.

Scope of Chapter and Sources of Data

Area Coverage

In determining the regions to be covered for the revised National Power Survey, the Federal Power Commission set out the South Central Region as one area. The South Central Region encompasses the Texas intrastate utilities, which cover Power Supply Areas 37 and 38, and all of the Southwest Power Pool utilities except those in Nebraska. The area of the Southwest Power Pool included in the South Central Region encompasses Power Supply Areas 25, 29, 33, 34, 35, and part of 17–F in Kansas and Missouri. Figure 1 shows the areas covered by the South Central Region. FPC statistical Region V encompasses all of the South Central Region except PSA 17–F and also includes PSA's 36 and 39. Data on Region V is not included in this report but a large amount of FPC's statistics have for many years been issued by these statistical regions. Some references to Load Study Areas are made in this report and these were the areas used in the first National Power Survey. These appear on Figures 6 through 12.

The boundaries of power supply areas are set according to the service areas of major electric utilities, groups of utilities, and operating power pools. These boundaries are occasionally adjusted to meet the changes in utility ownership, pooling, or coordination arrangements. Generation and transmission cooperatives and Federal marketing systems have developed transmission networks which transcend the service areas of other major utilities so as to reach preference wholesale customers. It has therefore not been possible to readjust power supply area

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boundaries to conform to the service areas of all principal utilities. The data for each power supply area, however, represents full coverage of all utilities in the area, large and small, regardless of ownership. Minor adjustments of data are occasionally required where utilities overlap power supply area boundaries. Isolated electric utility systems are included in the area totals and represent only a very small percentage of the total. Industry-owned generation is not included in the data in the report except in Tables 9 and 11. This load forecast includes loads in the areas whether met by system generation in the area or whether met by imports from outside the area.

Data Sources

The FPC has compiled historical data on electric utility load growth and classified sales data since prior to 1940. These statistics are reported annually to the Commission on power system statements and these are supplemented monthly with load and capability data. The 4-year load forecasts provided by the utilities provide a short-range estimate by company planners. To supplement this information, field engineers of the Federal Power Commission visit electric utility officials annually and, among other things, discuss long-range load forecasting methods and expected loads ten to fifteen years in the future. Load forecasting techniques are often reviewed. The FPC maintains historical records of electric utility operating data on all systems and this is available to interested persons.

Economic Indicators

A number of economic indicators affecting the development and trending of future electric utility load growth are used for reference in these forecasts. Department of Commerce, Bureau of Census projections of population provide a principal guide for the farm, residential, commercial, and street lighting estimates. The Department of Labor statistics on industrial employment are useful in the industrial projection. The Department of Agriculture statistics on numbers of farms, persons per farm, and farm electrification loads are also used. Department of Interior, Bureau of Mines data on value of mineral products are always considered in industrial estimating. The value added by manufacture is a good reference index. National projections of the gross national product, and other economic indicators are used as general guidelines although, historically and in this forecast electric load growth outstrips most other economic trends. Comparisons of electric load forecasts are made with other types and total energy consumption. Reference is made to other general forecasts such as those of the Economics Research Service, Resources For The Future, Federal Reserve Districts, etc. State projections are used for comparison as, for example, those furnished by the Bureau of Business Research, University of Texas. (See Table 12.)

Population Projections

The population projection used for this report is the Series II–B estimate in the Series P–25 release issued by the Bureau of Census, U.S. Department of Commerce. This projection is based on a number of reasonable alternative assumptions concerning the redistribution of population through interstate migration and further assumes a moderate decline in the national fertility level from the present fertility level. Other series projections assumed a more substantial drop in fertility rates, but in all series the projections were developed by a component method in which the 1960 census population of each state by age, sex, and color was carried forward on the basis of population changes caused by births, deaths, and net migration. Population estimates include an increment to cover Armed Forces overseas.

The population is broken down between farm and non-farm so that energy use on farms may be related to farm population and the number of farm customers. Farms are tabulated according to the Bureau of Census definition. The non-farm population is directly related to forecasts of non-farm residential, commercial, and street lighting use, and is referred to in connection with the category known as "other."

The 1966 total population by Power Supply Areas varies from 1,161,000 persons in PSA 29 to 4,988,000 persons in PSA 25. The total population in the South Central Region in 1966 was 23, 238,000 of which only 2,052,000 were farm persons. The 1990 total population estimate is 33,060,000 persons of which only 1,941,000 are farm persons. The farm population is estimated to continue to decline during the period of this forecast due to the growth in sizes of farms, the migration to urban areas, and the trend toward commercial farming. Table 1 provides population estimates by power supply areas and for the South Central Region at 5-year intervals from 1965 through 1990.

The projections of population by the Bureau of Census are related to state boundaries. In order to develop similar data by power supply areas, historical trends of population by groups of counties are developed and projections are then made of population trends by power supply areas. Total population projections of power supply areas equal the sum of state projections as prepared by the Bureau of the Census.

Load Projections

Farm (Excluding Irrigation and Drainage Pumping)

In preparing an estimate of farm use (excluding irrigation and drainage pumping), the historical data on numbers of farms as defined in the Census of Agriculture is projected into the future. Numbers of farms have been decreasing due to low farm income, rapid growth in commercial farming, larger sized farms, higher equipment costs, increasing hourly labor costs, etc. Farm sizes are increasing and commercial farming is becoming "big business" in many areas—an example is cattle feed lot operations on the high plains of West Texas. Since rural electrification reaches substantially all rural areas in the country, the numbers of farms electrified as used in the load forecast is nearly as large as the total number of farms. In the South Central Region in 1966 there were 583,427 electrified farms and the number predicted for 1990 is 521,220 farms. A kilowatt-hour per customer use figure is applied to the number of electrified farms to arrive at total consumption. This use figure is based on historical trends, types of farming in the area, and predictions of future farming activities and new methods of electrification of farm equipment and machinery. Farm use per customer varies considerably in different power supply areas, and in 1966 varied from 3,839 kwh per customer in Power Supply Area 25 to 7,079 in Power Supply Area 29. The South Central Region, as a whole, had an energy use per farm customer in 1966 of 4,576 kwh, which is projected to reach 16,520 kwh per customer in 1990 as shown in Table 4.

The total farm use in the South Central Region in 1966 was 2,670 million kwh and is projected to grow to 8,613 million kwh by 1990, as shown in Tables 3 and 4.

Future farm population is determined by trends of numbers of persons per farm and total number of farms. This farm population is subtracted from total population to arrive at the non-farm residential population which is related to non-farm residential energy consumption.

Irrigation and Drainage Pumping

Irrigation and drainage pumping requirements are predicated on historical trends and an examination of future requirements, keeping in mind amounts of irrigable land and water supplies available for irrigation. Should the Texas Water Plan for diversion of northeast Texas water resources to the more arid southwest Texas areas materialize to some degree prior to 1990, the current forecasts in PSA's 33, 37, and 38 may need to be modified to include the pumping requirements. Further, should the movement of surplus water from the Lower Mississippi River below New Orleans begin to move into west Texas prior to 1990, forecasts may need to be modified in not only PSA's 33, 37, and 38 but also in PSA 35 and perhaps PSA 25. This latter plan is now under preliminary study by the Corps of Engineers and the Bureau of Reclamation in cooperation with the States of Texas and Louisiana.

The irrigation and drainage pumping requirements vary from year to year based on rainfall and drouth conditions. The two principal areas where sizeable requirements occur are in PSA's 25 and 38. Energy requirements in 1966 were 116 million kwh and 123 million kwh in these two areas, respectively. By 1990 these two areas are projected to reach 325 million kwh and 350 million kwh. For the South Central Region as a whole, irrigation and drainage pumping energy requirements in 1966 were 346 million kwh and are projected to reach 984 million kwh in 1990, as shown in Table 3.

Non-Farm Residential

In the preparation of a load forecast for non-farm residential sales, types of appliances and energy use per appliance were determined for the average home for 1965 and 1966 and predictions are made for the South Central Region as a whole. These projections provide guidance for determining appliance saturation and include an increment for the potential development of new appliances. In this respect, it is interesting to note that there have been very few new appliances developed for the home in recent years that use sizeable quantities of electric power. Many appliances and domestic uses have increased in size and in electric consumption. The current and future trends of non-farm

residential appliance saturation and energy consumption are shown in Table 10.

In preparing the energy forecast, the non-farm residential population was divided by the number of persons per residence to arrive at the number of residential customers. One hundred percent electrification was assumed. The kilowatt-hours per customer were projected by power supply areas and an examination of these trends shows that they show regular annual increases. In 1966 the use per customer ranged from 4,239 kwh in PSA 17–F to 6,460 kwh per customer in PSA 38. For the region as a whole, the 1966 usage was 5,310 kwh per customer and this was projected to reach 18,510 kwh per customer in 1990. These data are shown in Table 4.

The total non-farm residential energy consumption in 1966 in the South Central Region was 33,178 million kwh and this is projected to reach 242,760 million kwh in 1990, as shown in Tables 3 and 4.

Commercial

In order to relate commercial energy sales to population trends, the number of persons per commercial service is calculated by power supply areas and trended by years for which historical data are available and extended to 1990. The kilowatt-hour energy consumption for commercial service was trended historically and projected to 1990. In 1966 the commercial use per customer ranged from 23,147 kwh per customer in PSA 34 to 39,523 kwh per customer in PSA 17–F. The average usage in the South Central Region was 30,063 kwh per customer in 1966 and this was projected to reach 99,630 kwh per customer in 1990, as shown in Table 4.

The total commercial energy use in the South Central Region was 27,248 million kwh in 1966 and this was projected to reach 134,235 million kwh in 1990, as shown in Tables 3 and 4.

Industrial

The industrial classification of energy sales is the largest single category and is expected to remain the largest throughout the period covered by this report. Historical trends of industrial sales are examined, plotted, and extended into the future based on judgment, information obtained from the electric utility industry, economic indicators, and industrial statistics available from federal agencies, state bureaus, and other sources. As a guide in the projection of industrial trends, the regional office of the Federal Power Commission maintains a card file of existing and projected industrial customers on which production, employment, and other statistics are entered. Further, electric utility requirements of principal segments of the industrial category are plotted for such as cement, refineries, petrochemical plants, etc., when adequate data can be assembled. Industrial sales represent by far the most difficult category to predict into the future. It can readily be seen that one new major aluminum reduction plant supplied by the electric utility industry could radically affect industrial sales in any power supply area. As a whole, however, the forecast attempts to provide for new plants and new industrial processes that may be developed during the period covered by the forecast.

Industrial production, while subject to fluctuations of short duration, has shown a persistent upward trend since the beginning of the Industrial Revolution. The Federal Reserve Board index of industrial production provides a good economic indicator for the power supply areas in each Federal Reserve district. The gross national product is also used as a reference but, like other national indicators, cannot be directly factored into a load forecast. The industrial energy requirements in 1966 varied from 1,600 million kwh in PSA 29 to 13,275 million kwh in PSA 38. The total for the South Central Region in 1966 was 51,039 million kwh and this is projected to reach 418,963 million kwh in 1990, as shown in Table 3. The above projections of industrial growth do not include industry-owned generation.

Table 9 provides statistics on industry-owned generation in addition to the above sales by utilities to industrial customers—together they represent total industrial energy requirements. Increases in industry-owned generation have been very moderate and the requirements in 1965 were 30,781 million kwh and this is predicted to increase to only 51,940 million kwh by 1990 in the South Central Region. Also in Table 9, the industry-owned generation and industrial sales are combined with other electrical sales to provide the total energy requirements. In 1965 for the South Central Region, the total requirements were 149,422 million kwh and this is expected to reach 952,320 million kwh in 1990.

Street and Highway Lighting

The energy requirements for street and highway lighting provide a very smooth trend of growth. These sales are related to numbers of non-farm residential customers and the future projections are

based on this relationship but keeping in mind street and highway lighting promotional programs for safety and crime prevention. In 1966 total energy requirements for street and highway lighting in the South Central Region reached 970 million kwh and this is projected to reach 4,265 million kwh in 1990, as shown in Table 3.

Electrified Transportation

The decreasing sales for electrified transportation are so small that no projected use is shown after 1970. Should it appear that highspeed electrified transportation will develop in the South Central Region, a commensurate projection of energy requirements must then be made.

All Other

This category of sales includes may different uses of electric energy such as Government facilities, water pumping, city buildings, utility offices, etc. In 1966 for the South Central Region, this classification was 4,890 million kwh. It is projected to increase to 18,355 million kwh in 1990, as shown in Table 3.

Losses and Energy Unaccounted For

Projections of losses and energy unaccounted for are based on historical trends. Losses represent a varying percentage of total energy requirements but the trends are fairly constant and can be projected with a reasonable margin. Upgrading of distribution facilities and major transmission extension programs affect losses. In 1966 losses in the South Central Region amounted to 11,217 million kwh and in 1990 are expected to reach 72,205 million kwh, as shown in Table 3.

Total Energy for Load

The total energy for load in 1966 was 131,565 million kwh for the South Central Region and by 1990 this figure is projected to reach 900,380 million kwh, as shown in Table 3.

Peak Demand

The monthly coincident peak demand in the South Central Region in 1966 was 27,440 mw. The monthly non-coincidental peak was 27,596 mw, producing a monthly diversity factor of 1.0056. The annual load factor in 1966 was 54.7 percent based on coincident peak. In 1990 the coincident peak demand is expected to reach 181,811 mw and the load factor is expected to increase to 56.5 percent, as shown in Table 2.

Load Centers

In order to facilitate the work of the Task Force of General Patterns of Generation and Transmission, the load forecast as shown in Table 2 by power supply areas was further broken down by load centers. As a guide in the selection of load centers and in trending their growth to 1990, actual data were compiled for 1960 and 1966. These data were based on information reported by electric utilities in the power system statements and annual reports to the Commission. Future estimates of load centers were prepared and load center maps for 1966, 1970, 1980 and 1990 were prepared for distribution to the Task Force of General Patterns of Generation and Transmission. Copies of these maps are provided as Figures 13 through 16. The largest load centers exceed 3,000 mw (3.0 gigawatts) and in 1960 only the Houston load center exceeded that size. By 1990, however, quite a number of the load centers will exceed 3,000 mw.

The minimum size of load centers was considered to be 100 mw for the study. Upon review of the preliminary load center data by the utilities, Middle South Systems requested some additional load centers and some of these were less than 100 mw and are shown as requested. Table 8 provides the statistical data on each of the load centers covered by the study. In each power supply area, some of the outlying isolated municipal systems and intervening areas are shown in the tabular data as "unassigned."

Seasonal Load Differences

Load Study Area—1960–1966

Prior to an examination of potential future seasonal load differences, the load study areas used in the first National Power Survey were examined to determine the actual seasonal differences within load study areas. The years 1960 through 1966 were analyzed as shown on Figures 6 through 12. The shaded areas represent summer peaking areas and the white areas represent winter peaking areas. All of the South Central Region is a summer peaking area and the amounts for Study Areas J and K in 1960 were 2,154 mw and 2,071 mw, respectively. By 1966 these seasonal differences had grown to 3,889 mw and 4,650 mw. Regions having substantial winter peaks are the TVA area and the Pacific

Northwest. A seasonal diversity exchange amounting to 1,500 mw, is now being made between the TVA area (Study Area F) and major utilities in Study Area K. Consideration is being given to extending this exchange to 2,500 mw if seasonal diversity potentials continue to increase, particularly in the TVA area. Study Area K as used in the first National Power Survey does not include the Kansas City and surrounding area (PSA 17–F) which is incorporated into the South Central Region for the revised National Power Survey.

Monthly Peak Demands and Energy Requirements

In order to facilitate consideration of seasonal diversity exchanges, monthly peak demands and energy requirements were projected by power supply areas based on historical trends back to 1960. A summary of this data for the South Central Region by months at 5-year intervals from 1960 to 1990 and also including actual 1966 data is presented in Table 5. Peak demands in the Region, as in all of the power supply areas, occurred in the summer months.

Summer and Winter Peak Demands

Table 6 is a tabulation of monthly energy and maximum peak demands for the summer and winter periods from 1965 to 1990 including actual data for 1966. This data is presented from each power supply area and is summarized for the South Central Region. In 1966 the South Central Region summer monthly coincidental peak occurred in July and amounted to 27,440 mw and the following winter peak occurred in December and amounted to 18,469 mw.

Table 7 summarizes the seasonal load difference in megawatts at 5-year intervals for the South Central Region and the two principal groups therein. For Power Supply Areas 37 and 38, the seasonal difference grew from 1965 to 1966 from 3,422 mw to 3,889 mw. The forecast projected this seasonal difference to increase by 1990 to 23,928 mw. For the other areas in the South Central Region (principally Southwest Power Pool), the seasonal difference increased from 4,262 mw to 5,158 mw from 1965 to 1966 and is projected to reach 32,172 mw in 1990. The seasonal differences from the South Central Region are projected to reach 56,100 mw in 1990.

Consideration of Future Seasonal Load Differences

It must be kept in mind that the theoretical seasonal load differences as projected in these forecasts can be greatly affected by changing load conditions such as winter heating loads encouraged by incentive electric rates. Areas now experiencing winter peaks may develop higher summer peaks due to the gradual encroachment of summer air conditioning. Further, a large portion of the theoretical seasonal difference is utilized by maintenance outage scheduling. Care must be exercised in projecting future load differences to provide adequate capacity for maintenance of large high-temperature units, particularly supercritical machines and nuclear-fired units. Further, caution should be exercised in predicting continued availability of potential seasonal differences due to changing load patterns.

Study of Peak Electric Load Duration During Heat Storm Coincident With a Drouth Period of Record

At the April 25, 1967 meeting of the South Central Regional Advisory Committee, the Load Forecast Task Force was instructed to determine the duration of heat storms experienced in the South Central Region and to review the shape of daily load curves that resulted and to recommend load and temperature data that would be used in studying the application of low-load factor conventional hydroelectric capacity, pumped-storage capacity, seasonal diversity capacity, and peaking thermal-electric generation resources in serving summer peak load demands. A pilot report was prepared in response to these instructions covering the system of Oklahoma Gas & Electric Company and a copy is included as Appendix A.

Summer peak loads in the South Central Region are predominantly temperature responsive and above average peak demands almost invariably occur during below-normal rainfall conditions. It is, therefore, imperative that critical year streamflow conditions be related to high-temperature conditions to derive a reliable basis for the development of future conventional and pumped-storage hydroelectric resources. Accordingly, load shapes of the Oklahoma Gas & Electric Company system were analyzed for the years 1954, 1964, and 1966. Figures 1, 2, and 3 in Appendix A show temperature and peak demands plotted for selected days in 1966, 1954, and 1964. It can be readily noted that there

is very close correlation between electric load and temperature. The increase in load on this electric system amounts to appoximately 1½-percent increase for each degree of temperature increase.

Figures 7 and 8 in Appendix A show temperature duration curves and number of days that maximum temperatures equaled or exceeded 100° F., respectively. In 1936, the maximum temperature was 113° and there were 43 days that the maximum temperature equaled or exceeded 100°. In 1954, 1964, and 1966, temperature equaled or exceeded 100° for 41, 21, and 23 days, respectively. In 1936, 1954, 1964, and 1966 the number of consecutive days the temperature equaled or exceeded 100° F. were 22, 10, 8, and 19. During consecutive hot days, electric load gradually increases until often relieved by afternoon thundershowers over at least part of the electric service area.

The report concluded that accurate daily and weekly load shapes could be developed for selected wider areas such as the Southwest Power Pool area and the Texas area. The report recommended that load curves be developed for such a group of systems based on temperature and weather conditions typical of those prevailing in 1936, the hottest period on record in modern times. This work was subsequently accomplished and is discussed in the following paragraphs.

Temperature-Load Characteristics of the Southwest Power Pool

Subsequent to the temperature-load characteristics study on the Oklahoma Gas & Electric Company system, the South Central Regional Advisory Committee requested that the study be expanded to cover the Southwest Power Pool. The purpose of this expanded study was to determine the load shape and duration of the hourly load curve that would result from a recurrence of the heat storms of 1936 and 1954.

In accomplishing the study, hourly loads for July and August 1954 and 1966 were obtained and used for all of the Southwest Power Pool and separately for Oklahoma Gas & Electric Company, Southwestern Electric Power Company, and the Middle South System. Hourly dry bulb temperatures for the same periods were determined for eight principal cities in the area under study. This data comprising over 30,000 figures was computerized and relative temperature-load shapes developed as shown in the report covering the study, which is Appendix B in this report. The results are presented graphically in Appendix B for the peak weekly period of 1954 and 1966 as Figures 1 through 8 and demonstrate that peak period loading for the Southwest Power Pool is a temperature responsive mechanism. It is also apparent that 1954 was hotter than 1966 and that high temperatures and loads were sustained for the entire week. The 1954 curve has a broader shape but has troughs at 1 p.m. and 7 p.m. The wider shape is due to the greater temperature duration of 1954 and would be expected to be reproduced in any year with similar temperatures. The reduced 1 p.m. and 7 p.m. troughs in the 1966 load shapes indicate a trend to longer and smoother persistence of daily peaks.

The study was limited to dry temperatures because of data availability. However, an analysis by Oklahoma Gas & Electric Company indicates that the "THI," or temperature humidity comfort index, has little effect on the peak load. Energy consumption does correlate with the number of THI degree days experienced. In Oklahoma, high temperatures are always accompanied by low humidity. During the ten years from 1954–1964, temperatures of 100° or over were recorded 398 hours, and 83 percent of this time the humidity was in the range of 0–29 percent. Humidity in the coastal cities could have a greater effect on the load shapes but none of these cities experiences temperatures over 100°. The study for the Southwest Power Pool, to a considerable extent, provides for temperature diversity throughout a large operating region as temperature input data was used from Kansas City, Missouri to Beaumont, Texas.

In conclusion, a heat storm of the proportions of 1936 or 1954 would produce one or more periods of five substantially successive days with essentially the same peak load each day. The principal change in the load shape of the daily load curves since 1954 has been the elimination of the 1 p.m. and 7 p.m. troughs. Peaks increase rapidly during the morning and hold at high levels from around 11 a.m. until 9 p.m. after which a substantial reduction occurs. During sustained hot weather substantially high loads may occur from 10 a.m. until 10 p.m.

In examination of the application of conventional and pumped-storage hydroelectric capacity, seasonal diversity capacity, and thermal peaking capacity, the historical hourly load shape of the 1954 peak week, with smoothing to eliminate the 1 p.m. and 7 p.m. troughs, should be used.

CHAPTER 2

FUELS RESOURCES FOR THE SOUTH CENTRAL REGION

Introduction

In December 1967 the Task Force of Fossil Fuels Resources—with a questionnaire to 33 major utilities in the South Central Region—requested data for 1966 through 1990, in 5-year intervals, on estimates of future electrical energy generation by types of fuel. The questionnaire also requested data on present and anticipated future trends in fuels used for generation.

The results obtained on total thermal generation compare favorably with the 1966 through 1990 energy for load consumption figures for the same period of years, as shown on the Forecast of Power Requirements (Chapter 1). The estimated percentage breakdown according to type of future fuels for the South Central Region depends on availability, deliverability and price of the various fuels.

The estimated percentage of energy generation by nuclear plants in this chapter does not necessarily compare closely with the number of plants designated as nuclear in the plant list following Figures 20, 21 and 22, as the plant data was solicited and assembled separately by the Task Force of General Patterns of Generation and Transmission. Although considerable speculation was apparent in this part of the survey, the trend to nuclear fuel is very much in evidence by 1990.

Fuels Survey

Tabular Results

The Survey indicates the quantities and proportions of energy to be generated by thermal methods. Since hydroelectric generation in this region is small, it is omitted from the following tabulation and is not covered in this chapter.

The following tabulation is for the totals of thermal generation of all systems reporting:

South Central Region

Total Thermal Generation for All Systems Reporting[1]

	Years					
	1966	1970	1975	1980	1985	1990[2]
Thermal Generation (millions of kwhr)	116,033	172,118	264,824	405,662	608,463	933,799
% Coal	4.56	4.28	9.18	10.61	11.52	10.09
% Oil	.03	.07	.32	.20	.11	.07
% Gas	95.22	95.47	85.15	71.14	55.69	46.36
% Nuclear			5.24	17.98	32.63	43.45
% Internal Combustion	.19	.18	.11	.07	.05	.03

[1] These estimates depend on availability, deliverability, and price.

[2] 1990 figure on thermal generation incorporates the higher Gulf States Utilities Company energy estimates.

The estimated fossil fuel requirement corresponding to the generation by fossil fuel generating plants projected in the above tabulation is listed in the following table:

Year	Coal required for generation (million tons)	Oil required for generation (million barrels)	Gas required for generation (trillion cu ft)
1966	2. 46	0. 05	1. 22
1970	3. 2	0. 18	1. 64
1975	10. 2	1. 21	2. 17
1980	17. 6	1. 13	2. 68
1985	28. 6	0. 93	3. 12
1990	38. 5	0. 90	3. 90

General Discussion of Results

Over ninety percent of all known gas reserves in the contiguous United States lie in the South Central Region, and the utilization of relatively short pipelines with low operating costs has always given natural gas a substantial competitive edge over other fuels for thermal generating plants in the area.

Only three systems in this region utilized coal in any substantial quantity in 1966 and there are no nuclear-fueled plants in operation at this time. While natural gas reserves continue to increase, the present drilling activities and discoveries of new reserves show little promise of increasing at the same rate as the fuel requirements of electric utility companies during the next twenty-five years. All systems thus indicate plans for increased usage of coal or nuclear fuels in the period to 1990.

The southern portion of the region (Texas and Louisiana) has ample supplies of gas and oil, no mineable bituminous coal to speak of, and large deposits of lignite. In the central portion, Arkansas has some gas, oil and coal; Oklahoma has ample supplies of both gas and oil, and some coal. The northern portion (Kansas and Missouri) has large supplies of coal and some oil and gas. Coal is being used in increasing quantities in Missouri for power generation and will be utilized earlier in Missouri and eastern Kansas than it will in the remainder of the region; although a lignite-fired plant in Texas is scheduled for operation in 1972. Coal could also be used early in the study period along inland waterways where the coal could be transported by barge.

It appears from data submitted by systems within the region that individual company estimates of future coal prices and installation costs of coal-fired plants compared to estimated nuclear fuel prices and the capital cost of nuclear plants are widely divergent, with some systems projecting new installations after 1975 almost all-nuclear and others virtually all-coal. Other systems project installation of nuclear plants early in the period, followed by the installation of coal-fired units, in order to obtain a mix of base-load capability and peaking capability.

As to the pattern of development of nuclear capacity, it can be said that nuclear plants will probably develop first in the northern part of the SCRAC region where fuel costs are higher and where the alternative plants may be coal-fired.

In 1966, of all thermal-electric generation in this region, 95.22% was from gas-fired plants and 4.56% from coal-fired plants. By 1980, the breakdown is forecast to be 71.14% natural gas, 10.16% coal, and 17.98% nuclear. By 1990, the forecast is 46.36% natural gas, 10.09% coal, and 43.45% nuclear.

We must recognize, however, that these projections are made on the basis of current nuclear technology and projected costs. Although 43.45% of all thermal generation is forecast to be from nuclear-fueled plants by 1990, the ultimate development will depend upon the competitive race between suppliers of nuclear fuel and coal.

Fuel Oil

One source of thermal energy which does not show up significantly in this projection is fuel oil. (See Figure 17—Distribution of Oil Reserves, South Central Region.) Only two systems in this region forecast any substantial use of fuel oil for generation during the period. Oil may contribute significantly to the generation requirements of most of the systems as the price of natural gas increases. Many steam generators now equipped to burn only gas can be inexpensively converted to fuel oil operation, while the cost to convert to coal might well be prohibitive. Fuel oil may be particularly attractive in areas along the Gulf Coast and the newly developed inland waterways because of the accessibility of these areas to oil from refineries along the Gulf Coast and imported foreign oil.

Peaking Capacity

It would appear that if this region is to attain the projected generation from nuclear plants by 1990, there must also be installed a substantial amount of peaking capability to utilize the low-cost

off-peak generation available from the nuclear plants. This could be from pumped-storage hydro, gas turbines or some alternate development. It is noted that data submitted does not reflect plants to utilize any significant capacity of peaking gas turbines.

Energy Storage

Other methods for the storage of energy during off-peak periods must be explored in order to more fully utilize the large generating units of the future. Several companies in this region are now sponsoring such a research program, directed toward studies of energy storage and conversion.

Fuel Transportation

In the past, fuel transportation has not been a serious problem for the majority of electric utilities in this area. This enviable position resulted from the use of easily transported natural gas to meet most of their fuel requirements. Considering the increased future use of coal discussed above, the transportation problems inherent to its use that now concern only a few, may become more widespread in this region depending upon the location of future plants.

For plants located near major load centers, "unit train" deliveries of coal will probably prove most economical. This method is now in use from northeastern Oklahoma into the Kansas City and southern Missouri areas. Unit trains are also planned from Kansas strip mines by 1970 and will be utilized more and more as anticipated rate improvements make them more attractive.

With a relatively small use of coal in the past, neither inland nor coastal barges have been utilized for coal transport in this area. Such movement is entirely feasible, however, on both the Mississippi River and along the Gulf Coast. After 1980, several plants in Arkansas and Mississippi plan to barge coal from the western Kentucky fields via the Mississippi River.

Barging of coal will also be possible on the Arkansas River navigation system after its completion in 1970. Some of this movement will be the shipment of coal out of eastern Oklahoma fields to other areas. Plants located near both the waterway and coal fields will probably utilize short hauls by truck or rail direct from the mine to the plant, so as to eliminate the expense of double-handling for relatively short barge hauls.

On the other hand, future transportation costs for coal may make attractive the alternative of locating the generating plant at the fuel source and transmitting the power rather than the fuel to the load area.

Although specific plant locations will require individual economic studies as to the comparable costs of transmission lines versus fuel transportation, mine-mouth plants are anticipated in eastern Kansas, western Arkansas and in the eastern and northeastern areas of Oklahoma after 1980. Lignite-fired plants in north central Texas planned for 1972 and later will also be mine-mouth installations. Systems in Kansas and Missouri already utilize mine-mouth plants, one using approximately 1.5 million tons of coal annually. Other such installations are planned for that area up to 1980, at which time all economically feasible coal resources are expected to be under contract.

Although the air pollution problem may possibly be a factor in the location of some future coal-fired plants in the region, the greatest incentive for selecting mine-mouth sites will be the extensive system of EHV transmission lines available. Present and future 345 and 500 kv grids in the area will be used to transmit power from plants at mine-mouth or along inland waterways with minimum additional transmission investments.

Many of the transportation problems which have affected the competitive status of coal-fired plants in the past will disappear in the next decade, as utilization of the EHV grids permits location of plants near the fuel rather than near the load center.

Gas Contracts

Pipeline saturation of most gas-producing areas by interstate pipeline companies, higher drilling costs for deeper production, and the increase in gas consumption to a point that equals or exceeds newly found reserves, have changed the natural gas market in the last decade from a "buyer's" to a "seller's" market. This change has allowed the seller to become more demanding with regard to restrictions imposed in the purchase contract. There are some views that higher exploration costs and pricing regulations somewhat dampens gas exploration. In the overall, it would appear that this market trend will continue.

Fuel Resources

Natural Gas

In the report, "Future Natural Gas Requirements Of The United States," Vol. 2, June, 1967, pre-

pared by the Future Requirements Committee under the auspices of the Industry Gas Committee, projection of total gas requirements by areas is indicated. Gulf Coast-Region 7, includes Texas, Louisiana, Arkansas, and Mississippi. Mid-Continent-Region 6, includes Kansas, Oklahoma, and Missouri. (See Figure 18—Distribution of Gas Reserves, South Central Region.) "Gas Facts", an American Gas Association publication, shows proved recoverable reserves at the end of 1966 by states. The tabulation below, which lists requirements, reserves, and amount of net reserve added in 1966, may be informative. A considerable portion (about 51 percent in 1965, 1966 and 1967) of the gas produced in Regions 6 and 7 moves into other regions through the interstate pipeline systems. Therefore, the growth of requirements in other regions is of great significance but the table below may furnish some indication of the magnitudes of total supply and requirements.

The net producton of natural gas in Regions 6 and 7 in 1966 was 14.5 trillion cubic feet. Of this amount, 6.9 trillion cubic feet (47.6 percent) was consumed in the area and 7.4 trillion cubic feet (51.0 percent) was exported; the remaining 0.2 trillion was either losses or placed in underground storage facilities. Of the 6.9 trillion cubic feet consumed in Regions 6 and 7, the generation of electric energy in the South Central Region accounted for 1.22 trillion or about 17.7 percent. In 1990, the requirements of gas-fired generating plants in the area is estimated to be 3.9 trillion cubic feet—26 percent of the total requirements of the area projected to be 14.9 trillion cubic feet.

Future gas production will depend on several factors including the amount of reserves added each year and the growth of the requirements within and outside of the Region. If the exportation of gas remains at 51 percent of the production throughout the study period, the required annual production in 1990 is estimated to be more than double that of 1966. If this level of production is reached, the projected gas requirements for electric generation in the Region will represent about 12.8 percent of this production.

Recent sales of leases for drilling off the Louisiana and Texas shores indicated a great deal of interest in such development. It is possible that considerable quantities of gas exist off the Louisiana and Texas shores that will be developed as fast as economics will permit.

Natural gas was originally flared in many oil fields because there was no use or market for it. The market for it and pipeline systems started growing after World War II. In the early days, some of the contracts by pipeline systems for gas were as low as 3¢ to 5¢ per Mcf. There have been examples in the past few months where gas has been bought in the field as high as 21¢ per Mcf. The projected cost of natural gas in 1990 ranges from 21¢ per million Btu to 38¢ per million Btu, with the median being about 30¢ per million Btu.

Coal

Although coal does not supply a major portion of the requirements of fuel for power generation at this time in the South Central Region, it appears that it will play an increasing role beginning in the late 1970's. This is evidenced for the majority of systems seriously considering use of coal and lignite as a fuel for units projected during the period.

The Region had an estimated coal reserve at the end of 1966 of 112,383 million short tons located mainly in Missouri, eastern Kansas, eastern Oklahoma, western Arkansas, and extensive lignite deposits in Texas. (See Figure 19—Distribution of Coal Reserves, South Central Region.) It is difficult to obtain accurate estimates of the reserves which can be economically recovered in the Region due to the many variables which must be considered. Some of these are costs of mining (which involve depth of overburden if strip mined), depth of seam, improvements in efficiency, wage rates, and the effects of competitive fuels.

In reviewing the estimates shown in Table 13 it appears that the Region has sufficient reserves to provide the necessary coal and lignite to supply the requirements as estimated during the study period, but recovery costs would dictate whether coal would

	Estimated or projected total requirements (billions of cu. ft.)					Total reserve end of 1966	Net reserve added in 1966
	1970	1975	1980	1985	1990		
Region 6	1, 391	1, 683	1, 714	1, 714	1, 945	36, 045	2, 295
Region 7	7, 437	8, 973	10, 182	11, 470	12, 961	211, 562	12, 464

be imported into the Region. Coal production in the South Central Region in 1966 was about 5.8 million short tons.

Breakthrough in some of the research projects involving gasification of coal at competitive costs would enhance the use of fossil fuel reserves which might not otherwise be available at competitive costs.

It is felt that the costs of coal in the period considered will rise due to the upward trend of operating costs but the percentage increase will be kept to a minimum by exploitation of unit trains, mine-mouth plants and the development of barging from fields outside the area. The estimated price of coal in the bunker varies from 17 to 29 cents per million Btu in 1970 to 25 to 31.5 cents per million Btu in 1990.

One major concern is the possibility of duplicating reservations on present coal reserves. While there now appears adequate reserves, an accelerated rate of dedication of economically recoverable reserves inside and outside the area will certainly change the fuel situation. For this reason, the transportation of fossil fuels by pipeline should not be ruled out although it has not been economically feasible due to a relatively small number of plants using large amounts of coal.

Lignite

There are lignite deposits in an area of 50,000 sq. miles in Texas, extending in a belt from the northeastern corner of the state in a southwesterly direction nearly to the Rio Grande. (See Figure 19—Distribution of Coal Reserves, South Central Region.) The area is not generally underlaid with uniform deposits, as has sometimes been supposed, but the deposits are in relatively small lens-shaped bodies. Deposits vary in thickness from a few inches to 14 ft. with most mineable deposits 6 to 9 ft. thick. In most cases the deposits are 40 to 150 ft. deep and both the floor and the roof are of clay or soft shale. There is an estimated 30 billion tons of lignite in the state, but much does not meet commercial standards.

Texas Power & Light Company was the first user of lignite in large quantities. Pulverized lignite was first used in 1926 to fire four steam generating units driving two 20,000-kw turbine-generators. Two more steam generating units driving a 35,000-kw turbine-generator were started in 1931. Due to the abundance of low cost gas, these steam generators were converted to gas firing by 1944.

Lignite was not used again for boiler firing until 1953. The three Alcoa 120,000-kw units at Rockdale have continuously been fired with lignite since that date.

Nuclear Activities in South Central Region

AP&L's Nuclear Power Plant

At present, there are no nuclear power plants operating in this region. However, Arkansas Power & Light Company plans to start construction in late 1968 on the first nuclear power generating station in the southwestern United States. This will be an 850,000-kw facility, will cost approximately $140 million, and commercial operation is scheduled for December 1972. The plant will be built on the Arkansas River near Russellville in northwest Arkansas on a 1,100-acre tract. The proposed site for this plant is on a peninsula at the Dardanelle Reservoir and is accessible by barge, rail, and interstate highway. Fuel loading is scheduled to begin in July 1972 and is expected to be completed in September of that year.

SEFOR Project

Seventeen investor-owned electric power companies, General Electric Company, the Atomic Energy Commission, and the Karlsruhe Nuclear Research Center of West Germany, are cooperating in the development of the Southwest Experimental Fast Oxide Reactor (SEFOR) near Fayetteville in northwest Arkansas. The purpose of the SEFOR research project is to obtain physics and engineering data at various fuel compositions, temperatures, and crystalline states characteristic of power reactor operating conditions. SEFOR is particularly designed for the systematic determination of the Doppler coefficient of reactivity at temperatures up to the vicinity of fuel melting.

The SEFOR project consists of two major parts: the design and construction of the reactor facility and related research and development program. Funds for the design and construction of the facility are being provided by the investor-owned electric companies, the Federal Republic of West Germany and the prime contractor, General Electric. Research and development funds will be furnished by AEC. Total cost is estimated at $27 million. Reactor start-up is scheduled for late 1968. No power will be generated at the project; it will generate steam and heat exchangers will transfer the resulting heat from the steam to the atmosphere.

To move forward the day when a prototype fast-breeder reactor plant can be placed in operation, S.A.E.A. companies are joint sponsors of a $750,000 design study. General Electric will complete the study by 1970 in order to have preliminary design work completed for a plant in the 300,000-kilowatt range.

Texas Atomic Energy Research Foundation Program

The Texas Atomic Energy Research Foundation was formed in April 1957 and in May 1957 entered into a research agreement with the General Atomic Division of General Dynamics Corporation providing for support of research in controlled thermonuclear reactions at the John Jay Hopkins laboratory in San Diego, California. The initial contract was for a term of four years and it was twice renewed for a total term of ten years. It expired April 30, 1967.

In 1963, the Foundation began supporting research in fusion and plasma physics at the University of Texas. The initial research agreements have been extended periodically, the latest extension being that announced by Governor Connally in September 1966, under which the Foundation will continue to support fusion research at the University of Texas for an additional two years, that is, until April 30, 1969, in the amount of some $350,000 per year. Some work was also sponsored at Texas A & M University; this work was concluded on April 30, 1967.

The Foundation has conducted a number of ancillary activities in connection with its research efforts. These have included summer fellowships at General Atomic for Texas graduate students, visiting scientist and professor exchange programs with General Atomic, the four-day high school science symposiums which have been held annually at the University of Texas since 1960, and graduate level seminars on controlled thermonuclear research. The Foundation has participated in about 40 one-day science symposiums in various cities of Texas sponsored by the member companies and attended by some 24,000 students and teachers.

Westinghouse Fast-Breeder Development

Some twenty-two utilities, including several of this Region (Houston Lighting & Power Company, Dallas Power and Light Company, Texas Electric Service Company, and Texas Power and Light Company) are participating in the first phase of the Westinghouse Electric Corporation's liquid metal fast-breeder reactor development program, which Westinghouse is conducting at its facilities at Waltz Mill, Pennsylvania.

Because the fast-breeder reactor produces more nuclear fuel than it consumes as it operates, it holds the promise of producing electricity at a lower cost than any other presently known methods. The program will lead to the design and construction of a sodium-cooled fast-breeder reactor which will have a generating capacity between 200,000 and 400,000 kilowatts.

In addition to the twenty-two utilities that have agreed to support the first phase of the program, a number of other electric utility companies, along with the U.S. Atomic Energy Commission, have been invited to support the first phase of the project. Some of the utilities are providing manpower, as well as financing, for the first phase of the program. Some of the utilities participating in the first phase may elect to participate in the construction of a prototype plant to be built in the second phase.

Gulf General Atomic Project

More than 20 electric utilities of the United States, including several in the South Central Region, have contracted with Gulf General Atomic, Inc., for conducting a two-year research and development program to be completed about the end of 1969. The work is intended as initial steps toward the attainment of a full-scale gas-cooled fast-breeder reactor power plant for commercial utility service; it is aimed to demonstrate potential advantages of high gain breeding with economically attractive costs of power.

Uranium Development in South Central Region

Kerr-McGee Corporation Developments in Oklahoma

Kerr-McGee Corporation will construct a $25 million uranium conversion plant on a 1,500-acre site in Sequoyah County near Sallisaw, Oklahoma. The plant is being designed by Bechtel Corporation of San Francisco. It will utilize a modification of classical conversion processes wherein U_3O_8 is first refined by solvent extraction, after which the refined uranium is hydrofluorinated with anhydrous hydrofluoric acid and then fluorinated with ele-

mental fluorine. The plant is designed to handle some 5,000 to 10,000 tons of uranium ore per year.

Confluence of the Arkansas and Illinois Rivers, adjoining the western boundary of the site, forms the headwaters of the Robert S. Kerr Reservoir which is now under construction. The land is about 15 miles west of Sallisaw.

Project Gasbuggy

Some mention should be made of Project Gasbuggy, which was an underground nuclear explosion, to release natural gas, detonated in New Mexico on December 10, 1967; it may have been a success. Considerable amounts of gas were liberated and the radioactivity of the gas was less than anticipated, according to an announcement by U.S. Officials at the 17-nation disarmament conference in Geneva. The initial tests were taken from a reentry well drilled into the broken rock. Final results cannot be known for a year or two. The experiment is conducted by the El Paso Natural Gas Company, the Interior Department's Bureau of Reclamation, and the Atomic Energy Commission. Preliminary technical data has been released by the participants of the project. The scientists working on the project say the most important information to be obtained from the experiment—on radioactivity, gas flow increases related to fracturing, gas pressure and gas production testing—will be gathered and analyzed over the next year or more. After that, conclusions can be drawn about the results of the experiment.

Air Quality

Natural gas, a relatively "clean-burning" fuel, is in great abundance in the South Central Region. It is the principle source of primary energy for all uses, as well as for the generation of electric power. Thus, in 1966, except for Alcoa's lignite-burning plant at Rockdale, Texas, essentially all of the electricity in Texas, Oklahoma, Arkansas, Louisiana, and the western part of Mississippi was generated with natural gas. Practically all the coal which is being used for electric power generation in the South Central Region is consumed in Kansas and Missouri, where indigenous coal is more readily available at prices competitive with natural gas. The proportion of electric power generated with coal in the SCRAC region of Kansas and Missouri in 1966 was 8 percent and 64 percent, respectively. It is in this portion of the South Central Region, therefore, that air pollution abatement is becoming an issue of increasing concern. This is particularly so because of the anticipated 15-fold increase in the use of coal for electric power generation in the Region, most of which will take place in Kansas and Missouri. Some plans are underway for the construction of coal-fired capacity in Oklahoma and additional lignite-fired capacity in Texas. The use of residual fuel oil has been and is expected to remain at a very insignificant level.

In 1966, electric utilities in Kansas and the western portion of Missouri consumed about 2.5 million tons of coal, about 40 percent of it in the seven counties (both in Kansas and Missouri) surrounding Kansas City which encompasses the Kansas City Metropolitan Area. The projected use of coal for the entire Region by 1990, including new commercial developments in Oklahoma and the Texas lignite field, is 35 to 40 million tons annually. Although some coal may be brought into the area from the high sulfur-bearing coal fields of Illinois and west Kentucky by barge on the Mississippi and Arkansas Rivers, the bulk of the future electric utility demand will most likely be satisfied with local coal.

The coal reserves of the South Central Region are large; including all of the coal in Missouri, most of which is located in the western portion of the state, the measured, indicated and inferred reserves of coal in the Region exceed 110 billion tons. In addition, there are about seven billion tons of commercial quality lignite in Texas. Except for a relatively small share (3 billion tons) of high metallurgical grade coking coal, the bulk of the coal reserve in the Region is relatively high in sulfur content.

The near future prospects for the abatement of sulfur oxide emissions are not encouraging. Although much effort is currently being expended in the development of an effective method for limiting sulfur oxide emission, and although several processes are already being offered commercially and are being tested at scattered locations around the country, none of the proposed methods have yet been demonstrated to be adequate in full-scale, full-load application. To date, the only assured way of reducing sulfur oxide emissions is to reduce the sulfur content of the fuel—a rather dim prospect for coal-burning plants in the South Central Region where the bulk of the coal reserve in place contains 3 to 5 percent sulfur. In 1966, the coal as burned by the electric power industry of the Region averaged 3.2 percent sulfur.

The Kansas Power and Light Company in connection with Combustion Engineering Company is

testing the "dolomite injection—wet scrubbing" method (Combustion Engineering Process) in Units 4 and 5 of the Company's Lawrence Station. Installation of control equipment is nearing completion in Unit 4 which has a 125-mw, tangentially-fired steam generator and has been operating since 1960. Unit 5 is under construction for service in 1971. It will have a 420-mw, tangentially-fired steam generator. It is anticipated that this system will remove at least 83 percent of the sulfur dioxide and 99 percent of the fly ash.

If the test proves to be a success, the "dolomite injection—wet scrubbing" process will be considered at other coal-fired power plants in the region, at least until some other more effective method has been demonstrated.

Until, however, a satisfactory technology for limiting sulfur oxide emissions becomes available, pollution abatement efforts will have to give proper consideration to various alternatives, including erection of tall stacks and construction of new power plants at remote mine sites, in order to enable the continued utilization of local fuel resources.

At present there is considerable emphasis in the Missouri-Kansas area on air pollution abatement, as evidenced by the activity at federal, state and local levels. The federal government gave the growing air pollution problem official recognition when, in 1955, it authorized the Department of Health, Education, and Welfare (HEW) to conduct a program on air pollution, to engage in research, and to provide technical assistance to municipalities and state agencies.

In 1963 Congress passed the Clean Air Act directing HEW to initiate a broad program of research, to publish criteria on the various air pollution agents, and to provide technical assistance and other aids to state and local air pollution abatement agencies. Additionally, HEW was to administer federal aid grants to establish and maintain regional, state and local air pollution abatement programs. HEW's legal authority was limited to interstate pollution cases and then only when a specific request for assistance was made by the Governor of one or more of the states involved.

The Clean Air Act was amended in 1965 to provide a mechanism for preventing and limiting the spread of air pollution. The Air Quality Act of 1967, a further amendment of the 1963 Clean Air Act, reaffirmed the principle of state control over air pollution problems; however, it gave HEW greater powers of enforcement. HEW was directed to set up air quality control regions, publish criteria and information on control techniques, and to promote research. The states were to set their own standards; but, failing to do so, standards could be set by HEW and enforced through court action.

In an effort to initiate a program of air pollution abatement in the Kansas City Metropolitan Area, Kansas City, Missouri, and Kansas City, Kansas, have enacted ordinances to enable their air pollution abatement agencies to take the required action toward air pollution abatement.

A broader effort on the part of Missouri and Kansas to enact a bi-state compact is evident in that the two states have recognized that ambient air is not confined by the common boundary between them and that they are committed to a clean air program through eventual establishment of uniform standards and cooperative control and enforcement procedures.

CHAPTER 3

RECOMMENDATIONS FOR COORDINATED PLANNING AND DEVELOPMENT

The purpose of this chapter is to recommend practices that will increase the reliability of bulk electric power supply through coordination of planning and operation of interconnected systems in the area. The principles and practices outlined in this chapter relate to the interconnected systems of the electric utilities of the region responsible for providing reliable electric power service in those areas where each system holds itself ready, able, and willing to provide such service. Each individual system has the responsibility to (a) provide enough power and energy to supply its customers' requirements, and (b) to provide transmission facilities adequate to furnish the electrical requirements of its customers at system load centers. Usually, individual systems can discharge their basic power supply responsibilities more efficiently through participation in coordinated planning.

Need for Coordination

The growth of interconnections, the expanded use of EHV transmission, and the installation of larger generating units have made additional coordination among individual systems on an area basis essential in insuring the reliability of electric bulk power supply. It is believed that such coordination should be concerned with: first, the elimination of any possibility of cascading or propagating outages; and secondly, with any advantages that result through the coordinated planning of joint power supply. The interconnected systems in the South Central Region have already adopted certain practices and principles that have resulted in a comparatively high degree of coordination. The actions of these groups are recognized in the next section entitled "Existing Coordinating Organizations." The coordinating organizations will continue to expand as the systems grow and larger areas are included in the power supply studies for future expansion. The Southwest Regional Group of the Interconnected Systems Group embraces more systems (investor-owned, federal, state, G & T cooperative, and municipal) than any organization in the Region. Through it, uniform practices for interconnected operation have been achieved, and its role in the future will be even more important as additional systems become part of the interconnected system.

Existing Coordinating Organizations

Southwest Regional Group

The Southwest Regional Group (SWRG) is composed of 49 electric utility systems plus six other groups in the states of Nebraska, Kansas, Oklahoma, southeastern Missouri, Arkansas, Texas, Louisiana, and western Mississippi. The SWRG is a voluntary, noncontractual organization whose objective is satisfactory and effective operation between the various systems and groups within the Southwest Regional Group and with systems of neighboring groups. Membership is open to any electric system located in the above states.

The organization had its beginning in mid-1943 to coordinate the operations of the various systems to enable them to give good service to essential war loads in the area. In January 1945, the Southwest Regional Group was formally admitted to the Interconnected Systems Group. The following list of standing committees of SWRG demonstrates the activities, duties, and responsibilities constituting the functions of SWRG:

1. Advisory Committee
2. System Operators and Dispatchers Committee
3. Communications Committee
4. Tie-Line and Load Regulating Committee
5. Reserve Capacity Committee
6. Spinning Reserve Committee
7. Civil and Industrial Defense Committee
8. Information Committee

Membership in the Southwest Regional Group is as follows:

Arkansas-Missouri Power Co.
Arkansas Power & Light Co.
Middle South System
Southwest Power Pool
South Central Electric Cos.
Arkansas State Electric Coop.
Kansas Gas & Electric Co.
Kansas Power & Light Co.
Kansas City, Kansas, Board of Public Utilities
Central Telephone & Utilities Corp.—Western Power Div.
Central Kansas Power Co.
Central Louisiana Electric Co.
New Orleans Public Service, Inc.
Louisiana Power & Light Co.
Southwestern Electric Power Co.
Middle South Services, Inc.
Mississippi Power & Light Co.
The Empire District Electric Co.
Missouri Public Service Co.
Kansas City Power & Light Co.
St. Joseph Light & Power Co.
City of Springfield, Missouri
Central Electric Power Coop.
M & A Electric Power Coop.
NE Missouri Elec. Power Coop.
NW Electric Power Coop., Inc.
Sho-Me Power Corp.
Medina Electric Coop., Inc.
Independence, Mo., Municipal Lighting Plant
Missouri Utilities Co.
Associated Electric Coop.
Consumers Public Power District
Nebraska Public Power System
Omaha Public Power District
Grand River Dam Authority
Oklahoma Gas & Electric Co.
Public Service Company of Oklahoma
KAMO Electric Cooperative
Western Farmers Electric Coop.
Southwestern Power Administration
Central Power & Light Co.
Central & South West Operating Committee
San Antonio, Texas, City Public Service Board
Dallas Power & Light Co.
Gulf States Utilities Co.
Lower Colorado River Authority
Southwestern Public Service Co.
Texas Electric Service Co.
Texas Power & Light Co.
West Texas Utilities Co.
Austin Water, Light & Power
Houston Lighting & Power Co.
USCE, Dallas, Texas
Brazos Electric Power Coop., Inc.
Southwestern Electric Service Co.

Southwest Power Pool

The Southwest Power Pool is a regional coordinating organization composed of 15 investor-owned electric utility companies (Members); five additional companies called Supporting Members; and three public power systems which are Contributing Members. During World War II when it was learned that Arkansas was being considered as a location for a primary aluminum reduction plant, the Southwest Power Pool was organized by 11 of the present member companies or their predecessors, except that Texas Power & Light Company also participated. At the termination of the contract with Defense Plant Corporation in 1946, a new coordination agreement was signed which provided that the pool office would continue to function in a study and planning capacity. At the present time, the Southwest Power Pool coordination agreement is being reviewed and revised more along the lines of a reliability document and, further, to provide for extended membership, particularly to municipal electric systems. Under the auspices of an Executive Committee and an Operating Committee, the following coordination activities are accomplished:

1. Coordinated load projections are made, including present and future power requirements and capabilities of participants.
2. Coordinated system reserve analyses are prepared annually.
3. The Pool sponsors system stability studies.
4. Reports covering all segments of the industry are prepared showing joint participation and the staggering of generating facilities.
5. Load duration and power energy curves are prepared, including a monthly operating report showing actual load shapes.

The Pool is a coordinating and planning group and not an operating pool. As one of the 12 coordinating groups of the National Electric Reliability Council (NERC) which was formalized in New York on June 11, 1968, the Southwest Power Pool will:

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1. Develop interregional reliability arrangements;
2. Exchange information with respect to planning and operation matters relating to bulk power supply;
3. Review regional and interregional activities on reliability;
4. Provide independent review of interregional matters; and
5. Provide information where appropriate to Federal Power Commission and to other federal agencies with respect to matters considered by the council.

The present participants in the Southwest Power Pool are as follows:

Members:

Arkansas-Missouri Power Company
Arkansas Power & Light Company
Central Louisiana Electric Company, Inc.
The Empire District Electric Company
Gulf States Utilities Company
Kansas Gas and Electric Company
Louisiana Power & Light Company
Mississippi Power & Light Company
Missouri Public Service Company
Missouri Utilities Company
New Orleans Public Service, Inc.
Public Service Company of Oklahoma
Southwestern Electric Power Company
Central Telephone & Utilities Corporation—Western Power Division
Oklahoma Gas & Electric Company

Supporting Members:

The Kansas Power & Light Company
Kansas City Power & Light Company
Missouri Power & Light Company
Missouri Edison Company
St. Joseph Light and Power Company

Contributing Members:

Southwestern Power Administration
Nebraska Public Power System
Omaha Public Power District

South Central Electric Companies

The South Central Electric Companies (SCEC) is an association of 11 privately-owned electric utility companies operating in the South Central area of the United States. In 1959, Mississippi Power & Light Company started negotiations with Tennessee Valley Authority (TVA), using as a basis their 1951 contracts, and investigated the possible interchange of seasonal diversity capacity. Contracts were arranged by adjoining companies and through Mississippi Power & Light Company to TVA for the exchange of seasonal diversity of 1,500 mw by 1968. Additional service schedules under these contracts provide for deferred diversity capacity, firm power purchases, economy energy sales, and emergency service.

In order to implement the several contractual agreements, the participants signed a coordination agreement in 1964 which, among other things, provides for an operating committee whose primary duties are:

1. To review load and capability forecasts for the participants.
2. To conduct joint planning studies relating to the generating and transmission requirements of participants.
3. To determine minimum reserve capacity requirements.
4. To coordinate maintenance schedules.
5. To establish such operating procedures as may be beneficial to interconnected operation.
6. To establish budgets and approve expenditures.
7. To adopt methods for the determination of incremental power losses.

Member companies of the South Central Electric Companies are as follows:

Arkansas Power & Light Company
Central Louisiana Electric Company
The Empire District Electric Company
Gulf States Utilities Company
Kansas Gas & Electric Company
Louisiana Power & Light Company
Mississippi Power & Light Company
New Orleans Public Service, Inc.
Oklahoma Gas & Electric Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

Missouri-Kansas Pool

The Missouri-Kansas Pool (MOKAN) is a multi-contractual arrangement among five privately-owned electric utility systems operating in western Missouri or eastern Kansas or in both states. Discussions leading to the formulation of the MOKAN Pool began in 1959 and under date of March 28,

1962, the basic participants executed a General Participation Agreement which is the nucleus of the Pool and, in essence, provides for:

1. The further interconnection of their systems;
2. The sharing of reserve generating capacity as a means of reducing their reserve capacity requirements;
3. The exchange of standby service among such participants to maintain service reliability; and
4. A continuing operational and administrative relationship to achieve operating economies and reliability through coordinated planning, operations, transactions and arrangements among members and others.

In June 1965, three additional contracts (the Missouri Facilities Agreement, the Kansas Facilities Agreement, and the Missouri-Kansas Coordination Agreement) were executed providing for the construction of strong 345-kv interconnecting facilities to increase interchange capability among four of the basic participants and to provide interconnections to Union Electric Company and Oklahoma Gas & Electric Company.

Under the first mentioned General Participation Agreement, and Executive Committee was established for policy guidance and an Operating Committee was established with the following functions:

1. Determining operating rules and procedures, including the preparation of an Operating Manual;
2. Coordinating maintenance schedules;
3. Determining spinning reserve requirements;
4. Coordinating load projections;
5. Making stability studies and recommending additional transmission facilities as needed;
6. Coordinating standards for operation of interconnections;
7. Coordinating plans and recommending additional generating capacity installations and power purchase arrangements; and
8. Supervising all other phases of interconnected operation.

The basic participants have entered into satellite contractual arrangements with other area power suppliers and, in effect, these suppliers are "Satellite Members" of the MOKAN Pool, participating in reducing reserve capacity requirements, exchange of standby service, firm power and economy energy transactions, coordination of load projections, system planning, maintenance scheduling, and spinning reserve supply. The Basic and Satellite Membership of MOKAN Pool is as follows:

Basic Membership:

Kansas City Power & Light Company
Missouri Public Service Company
The Empire District Electric Company
Kansas Gas & Electric Company
The Kansas Power & Light Company

Satellite Members:

St. Joseph Light & Power Company
The Board of Public Utilities of Kansas City, Kansas
The City of Independence, Missouri
Central Telephone & Utilities Corporation—Western Power Division
Associated Electric Cooperative, Inc.

Missouri Integration Arrangement

The Missouri Integration Arrangement became operative in 1962 between three utilities operating in western Missouri and eastern Kansas and the Associated Electric Cooperative (an agent for the Missouri REA cooperatives). Under the arrangement and commencing on June 1, 1965, hydro capacity (478,000 kw) and energy are purchased from the Southwestern Power Administration and used to effect and share economies of operations through coordinated scheduling as follows:

1. By scheduling its delivery to meet peak loads of their interconnected systems;
2. By its exchange to take advantage of seasonal and daily diversity between system peak loads;
3. By its storage and the utilization of the total thermal generation for off-peak energy requirements to conserve water during low-water periods; and
4. By utilization of excess hydro energy as a substitute for higher cost thermal energy during flush water periods.

Signatories to the Arrangement are:

Associated Electric Cooperative, Inc.
Kansas City Power & Light Company
Missouri Public Service Company
The Empire District Electric Company

Texas Interconnected System

The Texas Interconnected System (TIS) is composed of a total of nine publicly-owned and privately-owned electric systems providing some 80 percent of the electric power requirements within the State of Texas. The purpose of TIS is to provide effective area-wide coordination of planning and operation of bulk power supply facilities to obtain maximum reliability. The Administrative Committee and Technical Planning and Operating Subcommittees have the following functions:

1. Determination of spinning reserve requirements;
2. Analysis of installed generating capacity requirements;
3. Transmission system study;
4. Investigation of interconnection requirements;
5. Transmission line loading under normal and abnormal conditions;
6. Review of automatic under-frequency load shedding relays and settings;
7. Adoption of criteria for planning and operations; and
8. Determination of bias settings.

Members of the Texas Interconnected System are as follows:

The City of Austin, Texas
Central Power & Light Company
Dallas Power & Light Company
Houston Lighting & Power Company
Lower Colorado River Authority
San Antonio City Public Service Board
Texas Electric Service Company
Texas Power & Light Company
West Texas Utilities Company

TIS is divided into two load control areas. Information on individual system condition which affects bulk power supply is channelled through the area load dispatch office to other members of TIS.

Texas Municipal Power Pool

The Texas Municipal Power Pool consists of three municipal electric systems and Brazos Electric Power Cooperative, Inc. The Cooperative serves 19 distribution cooperatives located in central Texas. The Pool provides for a Technical Committee to promulgate the following items of coordination:

1. Comparison ~~and~~ approval of load projections of members;
2. Coordinated generation installation schedules;
3. Exchange of capacity and energy;
4. Allocation of spinning reserve;
5. Coordination of maintenance outage schedules;
6. The investigation of installing economic dispatch facilities.

The planning for the Pool began as early as 1952 but did not reach fruition until 1963. The requirements for participation are negotiation with the existing members. Current members are:

Brazos Electric Power Cooperative, Inc.
City of Garland Municipal Electric System
City of Greenville Municipal Electric System
City of Bryan, Texas Municipal Electric System

Participation in Coordination

The number of electric utilities participating in coordination should be kept to a manageable size to permit effective communication and cooperation among all its members. The geographical area of coordination should be limited in extent so that adequate transmission ties and associated equipment may be constructed in such a way as to permit reliable and economical flow of electric energy throughout the coordinated area.

Coordination of planning, development, and operation of electric systems should be carried out by those interconnected electric utilities whose planning and operation of generation and transmission facilities have a major effect on the reliability of bulk power supply in the area. Any system that purchases its power supply, or a major part of its power supply, may participate in area coordination through the agency of the system that directly or indirectly furnishes its power supply.

Functions Requiring Coordination

Although the corporate functions and responsibilities of each member must be recognized fully, the interconnected group operates as a single system in some respects. (Certain aspects of bulk power supply planning and operation should be coordinated first by subgroups and then by the entire coordinated area.) Among the items that should be coordinated are:

1. Timing, size and location of new generating units
2. Amount and location of planned reserve capability
3. Operating voltages of major transmission lines
4. Timing, size and location of new transmission lines
5. Normal and emergency loading of interconnections
6. Relay characteristics and settings
7. Amount and location of spinning reserve
8. Interconnected system operation
9. Maintenance schedules
10. Load shedding procedures during emergencies
11. Operating procedures during emergencies
12. Criteria for system stability and reliability
13. Pollution abatement and control
14. Interchange of information.

Procedure for Coordination

General provisions for coordinated area planning and development and operation of the interconnected system should be set forth in a coordination agreement among the participants. Such an agreement should include the purposes, functions, organizational structure and procedures for effectively carrying out area coordination. It will probably represent a formal expression of policies and procedures that have evolved over a period of many years. It should assist each participant in discharging its individual responsibilities. Coordination must be effected without increasing or tending to increase the cost of service to one system in order to provide a benefit or benefits to another system.

Provisions should be made for the performance and evaluation of load flow and stability studies where such joint studies are required for effectively coordinating the planning and operation of the area's bulk power supply.

The Southwest Power Pool and the Texas Interconnected System are recognized as regional coordinating areas and each is represented on the National Electric Reliability Council.

Hydro-Thermal System Coordination

Operation of a combined peaking hydro-thermal generating system poses problems not found in either the all-hydro or all-thermal system. The combined hydro-thermal system must plan to use hydro capacity with its limited firm energy to supply annual system peak loads, if it is to be a reliable and valuable power supply component. Thermal power and energy is used to supply the remainder of the load, but in good water supply years advantageous fuel savings may be attained by using the excess hydro energy.

Hydroelectric peaking power projects, pumped-storage projects, and seasonal diversity power interchanges must be coordinated with thermal resources if they are to be a dependable source of power in the Region. Such peaking power projects with limited availability of energy are designed to carry part of the daily loads on the systems during the season that the annual peak loads occur. They are a reliable source of power only if capacity and energy are available for the duration of the period when the maximum peak load could occur.

Studies in the Region have established that during hot weather the daily peak load period extends over many hours. Peak load days in the Region occur when high temperatures occur, and records show that high temperatures have occurred on more than 40 days during each of several summer seasons. Many of the days of high temperatures are consecutive resulting from prolonged heat storms and drought. The magnitude, daily duration, and seasonal duration of peak loads that might occur are well established.

Coordination of hydro peaking capacity for increased reliability of bulk power supply requires the conservation of hydro energy at all projects, to make certain the maximum amount of hydro capacity in the area is available and dependable during extended and repeated daily peak load periods under the most severe conditions of heat storms and drought of record.

Coordination of pumped-storage capacity for increased reliability of bulk power supply allows as dependable capacity only that amount of pumped-storage capacity that can be shown to have enough energy so as to be available each day for the duration of seasonal peak loads, when assigned that portion of the peak load other than the portions assigned to other capacity with limited amounts of energy.

Some coordination of the peaking hydro capacity in the area has been achieved, and improved

coordination in planning the expansion of peaking hydro-thermal systems is a major goal of the Region for increasing the reliability of the power supply. Coordinated operation of existing hydro projects requires continual studies for re-evaluation of the amount of hydro capacity available during the periods of maximum heat storms and drought as the loads and resources of the Region change.

Survey of Systems in Region

In the South Central Region, there is a total of 628 utility systems engaged in the delivery of electric power and energy to approximately eight million customers. The following tabulation gives a breakdown as to ownership, capacity, and facilities as of December 31, 1966.

Ownership	Total	Number of systems engaged in generation & transmission	Number of systems engaged in distribution only	Number of systems engaged in generation & distribution only	Generating capacity	
					Megawatts	Percent
Investor-owned	31	27	1	3	25, 938	79. 3
Public (Non-Federal)	396	5	223	168	4, 796	14. 7
Cooperatives	205	13	192	0	650	1. 9
Federal	2	2	0	0	1, 329	4. 1
Total	634	47	416	171	32, 713	100. 0

As shown by the table, 416 or 66 percent of these utility systems are engaged solely in the distribution of electric energy obtained from others and, therefore, are not responsible for the planning, construction or operation of the bulk power supply facilities of the Region. About 80 percent of the power requirements are provided by the generation and transmission facilities of approximately 30 investor-owned systems. These systems have organized into groups for coordinated planning and operation of the bulk power supply, because such an arrangement keeps the size of the groups to a workable, efficient organization, immediately responsible to the needs of the customers and the opportunities to give better service.

The federal, state, and cooperative G & T systems supply over 8 percent of the power requirements of the Region, and these systems are interconnected with neighboring systems under suitable contracts that provide coordination to the extent agreed upon.

A questionnaire was mailed to 191 systems in the SCRAC Region soliciting answers that would reveal the extent of and the interest in coordination. The answers to the survey questionnaire by municipal systems that supply about 12 percent of the power requirements in the Region are analyzed in the following paragraph.

A total of 67 replies were received—37 from municipal systems. Of these, 7 are members of coordinating organizations and 15 indicated interest in coordinating organizations. These 15 municipal systems have generating capacity of nearly 500,000 kw and 10 of them—with a capacity of more than 450,000 kw—are interconnected with one or more neighboring utilities with whom some degree of coordination exists or is available. The remaining 5 municipal systems account for less than 0.15 of 1% of the generating capacity in the Region. A few of the answers indicate that the interest is solely for economic reasons rather than for coordination and reliability based on electric system rate structures. About 95% of the generating capacity in the Region is interconnected under agreements that individually provide the degree of coordination between the systems, and under which the benefits of advancing technology are shared by all the customers.

Future Coordinating Requirements

In planning the power supply facilities of the future, each system is responsible for the requirements that make up a successful and satisfactory regulated electric utility business, some of which are:

1. A well-planned power supply
2. Adequate transmission to load centers
3. A reliable system
4. Coordination with neighboring systems
5. Financial stability
6. Good service
7. Reasonable rates

8. Satisfactory relations with the public, its employees, its customers, its owners, and its regulatory bodies
9. Good management.

In this chapter for updating the National Power Survey with respect to coordinated planning and development, much emphasis has been placed on the reliability of bulk power supply and on the prevention of power failures that might affect large areas of the United States. Much of this emphasis stems from the Federal Power Commission report on the Northeast Power Failure of November 9–10, 1965. The power failure became widespread because all of the power systems over a large area are interconnected and operating in synchronism. It is undeniable that the power failure would not have been widespread had the systems been separated and not operating in synchronism. Had the systems been separated the advantages of some interconnections under stable operating conditions would have been foregone. A report on future coordination requirements must consider the advantages and disadvantages of interconnected in synchronous operation over large areas. There is a long history showing that areas of the United States have operated without interconnections with other areas in the United States, and that such areas have provided good service at reasonable rates. Only careful study and evaluation of all factors will determine if the establishment of interconnections between such areas would produce better service and lower rates for all affected systems.

The coordinated groups comprising the FPC South Central Region have planned capacity and transmission line additions, so the various groups of systems are self-sufficient and have a reliable power supply whether or not they operate in synchronism with a larger group. In planning for future coordination in the area, the major systems will be interdependent on other systems within sub-areas of the Region but capable of providing reliable electric service when the Region is separated from other regions.

Forecasts indicate that the electrical load in the Region in 1980 will be at least three times the present loads. There is no assurance that interregional transmission lines will keep pace with such growth because of economics and the changing demands of our society. Coordinated planning for the future requires consideration of intra-area systems with more dependence on generating facilities within the area, and less dependence on out-of-area power capacity and inter-regional EHV transmission lines. The high cost of rights of way, public demand for fewer overhead transmission lines, along with increasing requirements for very costly underground transmission lines, will continue to require self-sufficient and coordinated systems within the area to assure a reliable power supply under established criteria.

Inability to obtain unrestricted rights of way across lands owned by the federal government may increase the cost of future transmission facilities to such an extent that systems will provide reliable and economical service to the area with a minimum of such costly transmission facilities. Governmental bodies with jurisdiction may adopt regulations in the future requiring more and more costly underground transmission lines resulting in increased cost of electric service. The development of atomic power opens the way, in the future, for uniform prices on capacity and energy at the plant bus. With coordinated planning, large size nuclear generating units will be located in all areas of the country and economy interchange of power and energy will disappear. Economics may dictate a gradual trend to interconnected and self-sufficient power system groups operating out of synchronism with adjacent groups, although not necessarily without interconnections with such adjacent groups. Such interconnections might be DC. The area will receive reliable service at lower cost if the coordinated planning for future system development is governed by economics rather than by a requirement for a national transmission line network without regard to need, relative reliability, or economic justification.

Coordination of planning for future generating capacity and for future transmission lines must be done by those systems whose operations have a major effect on the reliability of bulk power supply. In discharging their responsibilities, such systems shall be responsible for load forecasts, the scheduling of new generating capacity, and the scheduling of transmission system additions, along with consideration of economics, service reliability and area coordination. These management functions are well established. Satisfaction of the public interest in the future requires more support of these principles by and closer cooperation with regulatory agencies of every jurisdiction that affect power system operation.

To enhance reliability and to increase overall economy in the area, future planning requires better

coordination between the systems with utility responsibilities and the Government hydro system that provides a limited amount of power. Such additional coordination is a goal that should be achieved in the area at an early date.

At the sixth meeting of the South Central Regional Advisory Committee, representatives of the Federal Power Commission explained the Commission's "Electric Power Reliability Act of 1967." A new law is not the solution of electric reliability problems in the future, and the investor-owned utilities are opposed to the proposed FPC bill. (See the attachment to the minutes of the sixth meeting on July 25, 1967.)

Coordination of power systems in this Region is well advanced and the principles of coordination are established and have been successful. These recommendations for further coordination of electric power systems for increased reliability at reasonable costs can be realized in the future so long as the regulatory bodies recognize the responsibility of electric utility management for power system planning, development and operation.

Reports

Most utilities in the coordinated area now report planned additions to generating capacity through the Edison Electric Institute Electric Power Survey. The information is valuable because it lets the public, the Federal Power Commission, and the manufacturers of electric equipment know that additional power supply facilities will be installed to provide for growing electrical loads.

It is recommended that pertinent information on coordination and load and capability studies be furnished the Federal Power Commission.

CHAPTER 4

GENERAL PATTERNS OF GENERATION AND TRANSMISSION

1970–1990

Introduction

The basis for the Task Force report on General Patterns of Generation and Transmission was information received from the various utilities in the Region in response to questionnaires from the Task Force. Other information used in this report was furnished by the Fort Worth Office of the Federal Power Commission. Additionally, other reports made by the South Central Regional Advisory Committee and its other Task Forces were used as source material.

The Task Force realized from experience that any such report of generation and transmission patterns which covers a period almost a quarter of a century into the future must be general in nature. One should not expect to request and receive specific and finite plans of generation and transmission patterns that far into the future. Therefore, the data received from the Companies tends to be specific for six to eight years into the future, and more general in nature for the latter years.

Even though information for the latter years of the period is more general, it is the custom of utility groups to make long range plans as a general guide for the development of their systems. Because of this, the G&T Task Force concluded that the systems would generally develop along the patterns shown in their report, while at the same time differing in specific instances.

It should be clearly recognized that the data contained in this chapter are estimates and projections. Their inclusion here in no way implies any obligation on the part of any entity to develop facilities in the particular manner delineated in this report.

This chapter covers the South Central Region. It indicates the load projections through 1970, 1980 and 1990. For these load projections, it indicates the general patterns of generation projected to supply the projected load. The patterns indicate general locations, proximity to load centers, hydro facilities, retirements, reserve and other criteria concerned with generation.

The transmission patterns indicate the expected development of transmission lines in each power supply area and interconnections to other regions.

Finally, the chapter indicates the balance between generation and reserve as against load for the period of the study.

Scope of Chapter

Area Included

The physical area of the South Central Region which is encompassed by this chapter includes the major part of the State of Texas, excluding some of the extreme western area; substantially all of the States of Kansas and Oklahoma; all of the States of Arkansas and Louisiana; the western half of the State of Mississippi; and approximately the southwest half of the State of Missouri.

This region includes FPC Power Supply Areas 17–F (part), 25, 29, 33, 34, 35, 37 and 38 (Figure 1 of this report shows these areas).

Load

The projected loads listed in this report (Tables 2, 3, 6, 8 and 18) are taken basically from the "Forecast of Power Requirements for the South Central Region 1970–1990" dated June 1968. These basic load projections were prepared by the Load Forecasting Task Force and were approved by the South Central Regional Advisory Committee in April 1967.

In May 1968 the Gulf States Utilities Company in PSA 35 advised that the 1990 load forecast in that power supply area was substantially below the level expected by the Company. Therefore, the Company furnished a higher estimate of load and

capacity and their recommendations are reflected in the 1990 estimates in PSA 35 in Tables 2, 6, 8 and 18.

Generation

Generation data gathered for this report are confined to amounts of capability, sizes of units and plants, and general locations in the various Power Supply Areas.

No effort has been made to determine the types of plants insofar as fuel is concerned except to indicate possible nuclear plant locations. Data on types of fuel and the amounts of energy produced by various types of fuels are included in Chapter 2 of this report, which was taken from the document entitled "Report of Fossil Fuels Resources Task Force" to South Central Regional Advisory Committee dated July 1968.

An adequate water supply for cooling purposes is assumed to be available for the period covered in this chapter. Nevertheless, the particular types of cooling water utilization are not known due to uncertainties of water use criteria which are being promulgated by the several states and the Federal government.

Transmission

The transmission lines (shown on Figures 20, 21 and 22) in this report are the result of a survey of the major power suppliers in the region. In most cases, the lines shown or listed are confined to voltages of 200 kv and higher.

Load Patterns

Rates of Growth

The compound annual rates of growth, of peak load demand for the South Central Region for the period 1945–1990 vary from a maximum of 13.1 percent during the period 1950–1955 to a minimum of 6.9 percent during the period 1985–1990.

While the greatest percentage annual growth occurred in the early part of this period, it is interesting to note that the annual increases for the last four of the five-year periods are projected to be 8.9, 8.1, 7.4 and 6.9 percent. These are all above the national average projections and indicate that a dynamic growth is expected in the region. Within the region, curves of Figure 2 indicate the greatest rate of growth will be along the Gulf Coast in Power Supply Areas 35 and 38.

Peak Season

Table 2 indicates that all of the Power Supply Areas in the South Central Region have summer peaks, the winter peak being approximately 70 percent of the annual peak hour. The summer peaks are caused by a very heavy air conditioning load throughout the region. For this reason, peak loads are very sensitive and responsive to temperature and humidity.

Peaks created by the air conditioning load tend to exist for many hours each day and may exist for a number of consecutive days during a summer heat storm. A typical day load curve during such a period indicates that loads in excess of 90 percent of peak exist for ten or more hours and loads in excess of 95 percent of peak exist for eight or nine hours.

The summer peak characteristic of the region provides an opportunity for seasonal diversity exchange. The Tennessee Valley Authority (TVA), directly to the east of this region, has a predominant winter peak due to a heavy electric heating load. Because the proximity of these two regions with diametrically opposed peak seasons has made a seasonal diversity exchange agreement mutually economical, eleven of the regional companies have entered into a seasonal diversity exchange agreement with TVA in the amount of 1,500 megawatts. Under a long-term agreement among the parties, the eleven regional companies under the name of South Central Electric Companies deliver 1,500 megawatts of capacity and 1,950,000 megawatt hours of energy to the Tennessee Valley Authority during the four winter months from November 16 through March 15. The following summer from June 1 through September 30, the Tennessee Valley Authority returns a like amount of capacity and energy.

This exchange of capacity and energy, received by each party during its peak season, has deferred for the length of the agreement the installation of 1,500 megawatts of capacity by each party. The fact that this exchange is seasonal in nature makes the power available during the entire period of each party's peak season of four months. This is a distinct and important difference from diversity due to time zones and other short periods where the exchange does not cover peak periods.

The amount of this seasonal exchange is tabulated in Table 14. The magnitude of the TVA–SCEC exchange far exceeds any other diversity exchange known to this Task Force.

Load Centers

The location of concentrations of load plays a predominant part in generating plant locations and routing of transmission lines. In the South Central Region, load is concentrated in a number of centers.

This is not to imply that the entire load of the center is concentrated in the particular city which gives the center its name, but rather the load is in an area surrounding the city and may extend over an area considerably greater than that of the city itself.

Generation Patterns

Locations

In an effort to determine the general pattern of generation in the South Central Region for the period 1970 through 1990, data were solicited from the principal power suppliers in each Power Supply Area in the region. Since most power suppliers determine types and specific sizes of generators only a few years into the future, five or six years normally, it has been difficult to get finite data for the periods 1980 to 1990.

Nevertheless, each Power Supply Area was solicited, and each area supplied information, specific or general. From these data a "Plant List for Possible Patterns of Generation and Transmission Development to 1990"[1] was prepared. In general, the list has been limited to plants of 250 mw and larger. The listing for 1970 should be quite accurate since plans for 1970 units are now firm.

The listings for 1980 are accurate insofar as firm plans have been made by some systems through 1973 and 1974. Additions beyond 1974 are the best estimates of the various systems at this point in time. The sizes of units, timing of installations and type of installations beyond 1974 are subject to many variables including actual load growth, relative costs of various fuels and installed cost of various types of generation.

The location of electric generators in the South Central Region depends on a number of factors among which are load centers, water supply, fuel supply, availability of sites, transportation facilities and many others. Some of these factors are briefly reviewed in the following sections.

[1] "Plant List" appears in Report following Figures 20, 21 & 22.

Load Centers

One of the factors, load centers, is naturally of prime importance. Figures 13, 14, 15 and 16 along with Table 8 indicate a number of load centers in each Power Supply Area. It is interesting to note the concentration of generating plants around the load centers of Houston, Dallas, Fort Worth, New Orleans, Baton Rouge, Little Rock, Tulsa, Oklahoma City, Wichita and Kansas City. Locating generation near load centers minimizes the need for transmission lines and at the same time increases reliability.

Water Supply

Water is a requirement in practically all methods of power generation at the present time. Some of the exceptions are power generation by internal combustion engines and gas turbines. Steam turbine generation is the type requiring the greatest volume of water; however, this is not consumptive use for the most part.

The greatest use of water in steam electric power generation is for the cooling and condensing of steam. In this sense, some water is lost by evaporation but many times more is thermally enriched or thermally polluted according to varying viewpoints.

At the present state of the art, nuclear steam generation requires about 40 to 50 percent more water per kwh generated than fossil fueled steam generation. This is due largely to the fact that nuclear steam is generated at lower pressures and temperatures than fossil fueled steam and thus is less efficient. The advent of high temperature and breeder reactors is expected to narrow this difference.

Water supply in the South Central Region varies from a maximum in the south and east areas of the region to a minimum in the western areas. Major rivers in the eastern portion and coastal areas apparently can provide water for once-through cooling for large installations. In other areas, principal reliance will need to be placed on reservoirs and ponds as sources of cooling water. It is anticipated that a portion of new installations may require cooling towers.

A major factor in the selection of sites for new steam-electric plants is the effect of water quality standards established pursuant to the Water Quality Act of 1965. These standards include limitations on maximum temperatures and on maximum temperature rises and are applicable to interstate streams and coastal waters. They are prepared by the states

and must be approved by the Secretary of the Interior. Approved standards are subject to enforcement by both the states and, under procedures established by law, by the Federal Government.

For additional information on water needs and resources, refer to Appendix E entitled "Future Cooling Water Needs and Resources for Thermal-Electric Generation."

Fuel Supply

While the predominant part of the projected generation is of the steam driven turbine-generator type, no distinction is made as to the fuel. At the present time, natural gas is by far the predominant fuel in this region with a small percentage of coal and only one nuclear-fueled unit scheduled for operation in late 1972. For detailed information on fuel and the amounts of energy produced by various types, reference should be made to Chapter 2 which was taken from the South Central Regional Advisory Committee "Report of Fossil Fuels Resources Task Force" dated July 1968.

With most of the gas reserves of the nation located in the South Central Region, it is no happenstance that the principal fuel has been natural gas. The availability of gas by pipeline to most any location in the region has minimized the problem of availability of fuel.

It is expected that coal will increase in use particularly in the northern parts of the region in the next few years; however, by 1990 the total use of coal in the region will not exceed approximately ten percent of the total fuel used including nuclear.

Although nuclear power has not developed in this region as quickly as it has in other areas because of the plentiful supply and competitive price of natural gas, it is expected to play an increasingly important role during the decade 1980–1990. Transportability of nuclear fuel makes it available over the entire region, and this eliminates one factor in the selection of plant sites.

Availability of Sites

It appears that available sites will be adequate throughout the period although at higher costs. As metropolitan areas continue to expand, and as the use of nuclear fuel expands, generating plant sites may be located farther from load centers, but not necessarily remote from them. By the year 1990, the loads are approximately five times the magnitude of the 1970 loads. It is also of interest to note from Table 15 that the average size of plants is increasing also, and maximum sizes by 1990 are four to six times as large as the maximums of 1970.

The fact that plant sizes are increasing means that the number of sites will not increase in proportion to the load increase; however, the individual sites must be of larger size. This is another reason why plants will be located farther from load centers than was formerly the case.

Transportation Facilities

Transportation facilities for the movement of power plant equipment to plant sites are available by water, rail or highway. The region is blessed with many rivers such as the Mississippi, Missouri, Arkansas, and others which lend themselves very well to barge transportation. This method of transportation will be used to an increased extent as the sizes of units increase. As evidence, the first nuclear steam supply system for this region will be transported by barge down the Ohio and Mississippi rivers and up the Arkansas River to the plant site on Dardanelle Lake, near Russellville, Arkansas.

Hydro Facilities

Table 16 contains a listing of hydro resources in the region by Power Supply Areas. It is to be noted that the column headed "Existing and Under Construction" totals approximately 2,400 mw. It can be assumed that this amount of capacity will certainly be on the line by or about 1970.

The Table indicates totals of 3,244 mw and 2,921 mw to be added by 1980 and 1990, respectively. This would indicate a total in hydro capacity including pumped storage and conventional hydro of 8,516 mw by 1990. It should be stated that while there are 6,165 mw of potential additions to hydro resources from 1970 to 1990, it is by no means certain that this amount of capacity will actually be built. The economic feasibility of a number of the potential installations are not currently firm and economic indicators are constantly changing. When alternative methods of peaking capacity are investigated, it may well be that certain of the potential hydro projects will not be the economic choice. Nevertheless, should all of the listed installations be made, hydro capability will be less than four percent of the total capability of the region in 1990.

The South Central Regional Advisory Committee Task Force on Coordinated Planning and Development appointed a subcommittee to consider the utilization of hydro capacity on the projected loads of 1980 and 1990. The conclusion of this subcom-

mittee is that the proposed hydro capacity for those periods can be fitted into the load shape of the region. The subcommittee report is attached as Appendix D.

Retirements

It has been an understandingly difficult task to obtain from all utilities their projected retirements of generating units as far into the future as 1990. As a result of this difficulty, uniform retirement criteria were adopted and applied as follows: (1) all thermal units that are 35 or more years of age at the end of 1970 and 1980 are considered retired as of those dates, and (2) all thermal units 30 or more years of age at the end of 1990 are shown as retired as of that date. An application of these criteria to generating units in the South Central Region produced the theoretical retirements shown in Table 17. As a point of reference, the retirements by 1990 will amount to about nine percent of the expected 1990 generating capability. It should be recognized that as actual retirements develop they will vary from the theoretical retirements.

Cost Comparison of Thermal Generation

There is attached as Appendix G a cost comparison of thermal generation prepared by the Fort Worth Regional Office.

Transmission Patterns

General Patterns of Transmission Development

A general rationalization of the projected patterns of transmission development as portrayed in Figures 20, 21 and 22 quickly indicates a close relationship to an expected continuation of the present growth of power system load densities but reflects consideration of expected future plant locations determined by cooling water resources, fuel supplies and other factors. The South Central Region must be considered in two separate segments not now operating in synchronism: (1) the Southwest Power Pool area and (2) the Texas intrastate area.

In the Southwest Power Pool area, the transmission network is completely dominated by the recently-constructed 345–500-kv South Central Electric Companies grid—developed to accommodate the SCEC–TVA 1,500-mw seasonal diversity exchange now in full operation. Connecting immediately to the north of the SCEC grid, additional 345-kv lines have been constructed by MOKAN Pool members. Transmission developments shown on Figures 21 and 22 conceive a continued strengthening of this basic grid. Strengthening will be accomplished by both new ties and added capability on existing ties. Higher voltages are not expected except in Oklahoma where the beginning of a 750-kv system is expected before 1990—a development related not only to load growth but also to coal and water resources in the eastern part of the state. In the event that the SCEC–TVA seasonal diversity exchange is increased it is now expected that the increase could be accommodated by an additional 500-kv tie rather than a transition to higher voltage. It should be noted that projected transmission lines pass near eastern Oklahoma and eastern Kansas coal fields and are in the proximity of Arkansas and Mississippi River navigation channels. The expected future transmission network in Louisiana, Mississippi, and Arkansas is basically represented by three 500-kv lines oriented north and south, two of which connect with the TVA area. These lines have three principal east-west interties and the two northernmost of these interties are continued west into Oklahoma. Further to the north, one 345-kv line passes into Missouri near the Mississippi River and four 345-kv lines are projected to emanate from Oklahoma into Missouri and Kansas. All of these ties connect to a substantial 345-kv network in Kansas and central Missouri. Referring to the "Plant List For Possible Patterns of Generation and Transmission Development to 1990," a number of large capacity plants are expected along the Mississippi River and Gulf coastal areas. Other concentrations of generating plants, as mentioned earlier, cluster around such major load centers as Kansas City, Wichita, Tulsa, Oklahoma City, Little Rock and Shreveport. Occasional other large plants are strategically located on the network as required by expected network operating conditions, water resources, fuel supplies, transportation, and other factors. The expected generating plants reaching 5,000 mw and larger present a real challenge to the network during a plant interruption. Future transmission requirements will be influenced by plant and grid performance.

In the Texas intrastate area the recent advent of 400 and 500-mw generating units has gone hand in hand with the development of 345-kv interties between major load centers. As unit sizes continue to increase existing 345-kv ties will be double circuited and new interconnecting links established. These

additions will be a strengthening of the principal transmission pattern—a triangle connecting the three major load centers of (1) Dallas-Fort Worth, (2) Houston, and (3) San Antonio-Austin-Corpus Christi. Extending to the west of this basic triangle stronger 345-kv ties will also be made to the Wichita Falls, Midland and Odessa load areas. It is not anticipated that higher voltages will be required as gas and nuclear-fueled plants can be situated near major load centers. The one or two lignite-fueled plants expected and the sprinkling of other plants drawn to east Texas and the estuarine areas by water resources can be accommodated on the projected 345-kv grid.

Regional reliability was greatly enhanced by the completion of the 345–500 kv grids described above. The further strengthening of this grid as projected on Figures 21 and 22 should have a most profound influence in maintaining good service reliability. Large blocks of power can flow from area to area during emergencies and help prevent brownouts during heat storms and minimize the effect of major capacity outages. From the standpoint of transmission capability between major load and generation centers, both the Southwest Power Pool and Texas intrastate areas are now in a strong position and are expected to remain in the forefront in this area—a fact which directly translates into better electric customer service reliability.

The projected transmission line patterns as indicated on Figures 20, 21 and 22 are the result of a questionnaire to the principal utility operators in each Power Supply Area. A review of these Figures will indicate an orderly development of high voltage and extra high voltage lines among generators, load centers and adjacent systems. There are also indicated strong interconnections to other regions.

Practically all transmission voltages are present in the region. The predominant extra high voltages through 1980 are 345 and 500 kv. By 1990, a pattern of 750-kv (normal) transmission is emerging in the western area of the region. Patterns differ among Power Supply Areas as indicated by the following comments.

PSA 17–F and PSA 34

The principal power suppliers in these Power Supply Areas from whom information was received are: Kansas Gas & Electric Company, St. Joseph Power & Light Company, City Utilities of Springfield, Missouri, The Empire District Electric Company, Missouri Public Service Company, Kansas City Power & Light Company, Associated Electric Cooperative and Southwestern Power Administration.

The major transmission lines 230 kv and above in these Power Supply Areas for 1970 include 345-kv lines from Oklahoma to Wichita to Kansas City, Kansas City to St. Joseph, Kansas City to St. Louis, and Kansas City to Neosho to Wichita. A pattern of 345-kv is thus emerging although the bulk of the transmission lines in these areas will continue to be operating at voltages less than 230 kv through 1970.

By the end of 1970, Power Supply Areas 17–F and 34 will have a 345-kv interconnection to the east toward St. Louis, a 345-kv interconnection to the northwest toward Nebraska, two 345-kv interconnections to PSA 29 and two 345-kv interconnections to Oklahoma on the south.

By 1980, many 345-kv lines are projected to be in service. Particularly, is this true around Wichita, Kansas and Kansas City, Missouri. New Madrid, Missouri has 345-kv lines projected from the north, west and south into that general area. An additional 345-kv interconnection is projected east from Lutesville, Missouri toward Joppa, Illinois. A 345/500-kv line is projected west from Wichita toward Denver, Colorado and Amarillo, Texas.

By 1990, a comprehensive 345-kv system of lines is projected. Many previously built lines are now paralleled by additional 345-kv lines. A number of additional 345-kv interconnections are projected to adjoining Power Supply Areas. The 345/500-kv line from Wichita toward Denver and Amarillo is projected to be converted to 500-kv operation by 1990. A 765-kv line is projected from Kansas City, Missouri to St. Louis, Missouri.

PSA 25

The principal power suppliers in this area are the four operating companies of the Middle South System—Arkansas Power & Light Company, Louisiana Power & Light Company, Mississippi Power & Light Company and New Orleans Public Service, Inc. In addition to these, Arkansas-Missouri Power Company operates in northeast Arkansas and southeast Missouri and Southwestern Power Administration operates in northern Arkansas and southeast Missouri.

The major transmission lines 230 kv and above in the Power Supply Area in 1970 are dominated by more than 700 miles of 500-kv transmission lines installed on the Middle South System. This

is part of the South Central Electric Companies EHV system to exchange 1,500 mw of seasonal diversity power with the Tennessee Valley Authority.

As a result of the diversity exchange between the South Central Electric Companies and the Tennessee Valley Authority, Power Supply Area 25 has two 500-kv interconnections with the Tennessee Valley Authority on the east, a 500-kv interconnection with Oklahoma Gas and Electric Company and a 345-kv interconnection with Southwestern Electric Power Company on the west, and three 500-kv interconnections with Central Louisiana Electric Company and Gulf States Utilities Company on the south and west.

Several hundred miles of 230-kv transmission also exist in this Power Supply Area. Two interconnections with the Southern System to the east are in service at 230 kv.

By 1980, additional 500-kv transmission lines are projected for this area particularly from Helena, Arkansas south to Vicksburg along the Mississippi River. Also additional 500 kv is projected from the nuclear plant at Russellville into the Little Rock area. During this same period (1980), the Southwestern Power Administration is projecting 500-kv lines to connect with the Oklahoma City-Shreveport 345-kv line north through Tuskahoma Pumped-Storage Project and Fort Smith, Arkansas to Springfield, Missouri. Also, a 500-kv tap from this line eastward through Bull Shoals to New Madrid, Missouri and another 500-kv line from Bull Shoals to Optimus Pumped-Storage Project is projected.

During this period, 230-kv lines are also projected in the Middle South Companies, particularly in Arkansas and in South Louisiana.

By 1990, a 500-kv line is projected from El Dorado, Arkansas to a new plant north of the Wilkes Plant of Southwestern Electric Power Company and the 500-kv lines are expanded north and east of the Little Rock area.

No voltages above 500 kv are projected for this area through 1990.

PSA 29

The predominant transmission voltage in this area for the entire period 1970 through 1990 will be 230 kv—it will be gradually strengthened throughout the period. Some 345-kv transmission is projected in the area around Topeka.

An interconnection west out of Wichita (PSA 34) toward Colorado (PSA 32) and Amarillo (PSA 36) is projected as 345 kv by 1980 and as 500 kv by 1990.

PSA 33

The principal power suppliers in this area are: Oklahoma Gas & Electric Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. They are all members of the South Central Electric Companies and participate in the seasonal diversity with the Tennessee Valley Authority. The transmission system in 1970 is highlighted by 345-kv transmission lines from Fort Smith, Arkansas to Tulsa to Oklahoma City and Oklahoma City to Shreveport. Additional interconnections to other Power Supply Areas include: a 500-kv interconnection from Fort Smith to Little Rock, a 345-kv interconnection from Shreveport to El Dorado, Arkansas, a 345-kv interconnection from Oklahoma City north to Wichita, Kansas and a 345-kv interconnection from Tulsa north to Neosho in Power Supply Area 34.

By 1980, many additional 345-kv lines are projected for this Power Supply Area and a 345-kv interconnection is projected from this area west toward Amarillo, Texas in Power Supply Area 36.

By 1990, a comprehensive 345-kv network has evolved in Oklahoma with additional interconnections to Kansas and Missouri. The predominant development in transmission for the entire South Central Region, however, is the emergence of a 750-kv transmission system in Oklahoma. Several hundred miles of 750-kv lines form a loop system in central Oklahoma. The 750-kv interconnections are extended from this loop towards Shreveport and west toward Amarillo, Texas in PSA 36. This is the basis of a more comprehensive EHV system in future years.

PSA 35

The principal power suppliers in this Power Supply Area from whom information was received are the Gulf States Utilities Company and the Central Louisiana Electric Company. Gulf States Utilities Company and Central Louisiana Electric Company are members of the South Central Electric Companies and are, therefore, participants in the seasonal diversity interchange with the Tennessee Valley Authority. As a result of this participation, the major transmission in this Power Supply Area in 1970 is represented by several hundred miles of 500-kv lines. This area is interconnected

with Power Supply Area 25 by two 500-kv lines from Baton Rouge; one, north to Jackson, Mississippi and the other, east to New Orleans. Construction of a 500-kv line from Beaumont, Texas to El Dorado, Arkansas was started in 1968 and will provide an interconnection to Arkansas (PSA 25) in 1970.

There is a small amount of 230-kv transmission in the vicinity of Beaumont, Texas and Baton Rouge.

By 1980, several additional 230-kv lines and interconnections are projected, particularly are additional 230-kv interconnections proposed to Power Supply Area 25 in the New Orleans area. Additional 230-kv lines are also developed west from the Beaumont area.

By 1990, additional 500-kv lines are developed in the Beaumont and Baton Rouge areas with several additional interconnections to Power Supply Area 25.

The greatest increase in transmission mileage is projected at 230 kv. At this voltage, hundreds of miles of line cover the area in a network.

PSA 37 and PSA 38

The principal suppliers in these areas are: Texas Power & Light Company, Texas Electric Service Company, Dallas Power & Light Company, West Texas Utilities Company, Houston Lighting & Power Company, Central Power & Light Company, City of Austin, City Public Service Board of San Antonio and the Lower Colorado River Authority operating as an interconnected group formally comprising the Texas Interconnected System (TIS).

A 345-kv transmission system connects the major load and generation centers of PSA 37 with the Houston area of PSA 38. This system is being expanded and added to so that by 1970 a minimum of a double circuit line will interconnect these generation and load centers. Much of the remainder of PSA 38 transmission network will have been expanded at 138 kv with preliminary work for additional 345-kv interconnections already under way.

By 1980, all the load centers of the principal suppliers in PSA 37 and PSA 38 with loads greater than 1.0 GW will have been connected to the 345-kv network. Also, much of the single circuit 345-kv network will have been strengthened by additional lines and double-circuiting of existing lines including the extension of the 345-kv system to the extreme south end of Texas.

By 1990, all the load centers of the principal suppliers in PSA 37 and PSA 38 will be connected together directly by 345-kv network. The basis of development of the 345-kv bulk transmission system will be that of using double circuit tower lines with ultimate capacities comparable to or greater than that of 500-kv single circuit construction.

Since the load centers of the TIS are widely separated geographically, there has and will continue to be a concerted effort to expand the generation and transmission plant so a reasonable ratio of load and generation is maintained within each load center and a strong EHV network exists between load centers. In all, the EHV network within these two areas will have been expanded threefold from 1970 through 1990.

There have been no transmission lines projected during the study period which would effect an interconnection between PSA's 37 and 38 and neighboring areas. The possibility of establishing interconnection tie lines for parallel operation between the Texas Interconnected System and the Southwest Power Pool has been evaluated but the EHV ties did not prove economically or technically feasible and would not improve reliability. Evaluation of such ties will continue to be made.

Resolution of Load, Capability and Reserve

It is the obligation of the operating systems in the region to install or acquire generating capability sufficient to meet the peak load requirements of the region plus a reasonable amount of reserve capacity for contingencies. The major operating systems have made known their intentions to do this, either by actual scheduling of specific amounts of capacity or by the statement that capacity sufficient to meet the peaks will be scheduled.

Table 18 indicates that projected loads increase from approximately 40,000 megawatts in 1970 to more than 190,000 megawatts in 1990. At the same time, capacity increases from approximately 46,000 megawatts in 1970 to almost 219,000 megawatts in 1990. At these levels, the reserve capability is approximately 7,000 megawatts in 1970, 18,000 megawatts in 1980 and 29,000 megawatts in 1990. Table 18 indicates that the reserve varies from 18.6 percent to 21 percent through 1980, but it is reduced to approximately 16 percent by 1990.

Table 15 indicates maximum plant and unit sizes. It is noted that the average of maximum plant sizes varies from 900 megawatts in 1970 to about 4,000

megawatts in 1990. During the same interval, the average of maximum unit sizes varies from 500 megawatts in 1970 to 1,400 megawatts in 1990. Table 15 indicates that for PSA's 17–F, 29 and 34, the percentage of unit size compared to power supply area load is much larger than the average percentage for the South Central Region. The major plants, both existing and future, are located in eastern Kansas and western Missouri due to the availability of water and fuel. The power from these plants is distributed over the MOKAN Pool grid to other areas to the north, south and east. As a percentage of peak load, the average maximum plant size decreases slightly from 1970 to 1980 and remains constant at about 17 percent; however, the average maximum unit size decreases from 10 percent in 1970 to 9 percent in 1980 and 6 percent in 1990. This decrease in percentage indicates that probably the sizes of units are beginning to level out to some degree, at least they are not increasing at the same rate as load is increasing. A result may very well be a decrease in the amount of reserves necessary to cover the loss of the largest unit on a system as reflected in the decrease in reserve percentages in 1990. For additional information on reserve requirements determinations refer to Appendix F.

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TABLE 1

Population Estimate for South Central Region (Including Armed Forces Overseas)

[Thousands of Persons]

PSA	Farm	Nonfarm	Total	Farm	Nonfarm	Total
	1965			1966		
17–F	....	....	1, 379	....	....	1, 386
25	550	4, 373	4, 923	528	4, 460	4, 988
29	228	925	1, 153	226	935	1, 161
33	384	3, 129	3, 513	372	3, 176	3, 548
34	251	1, 254	1, 505	247	1, 268	1, 515
35	171	1, 866	2, 037	167	1, 907	2, 074
37	312	3, 738	4, 050	306	3, 800	4, 106
38	207	4, 173	4, 380	206	4, 254	4, 460
Total	2, 103	19, 458	22, 940	2, 052	19, 800	23, 238
	1970			1975		
17–F	....	....	1, 416	....	....	1, 493
25	484	4, 763	5, 247	440	5, 178	5, 618
29	223	969	1, 192	224	1, 025	1, 249
33	348	3, 338	3, 686	350	3, 521	3, 871
34	238	1, 316	1, 554	235	1, 397	1, 632
35	152	2, 068	2, 220	148	2, 246	2, 394
37	292	4, 038	4, 330	285	4, 365	4, 650
38	201	4, 579	4, 780	200	5, 110	5, 310
Total	1, 938	21, 071	24, 425	1, 882	22, 842	26, 217
	1980			1985		
17–F	....	....	1, 588	....	....	1, 696
25	440	5, 645	6, 085	440	6, 159	6, 599
29	228	1, 094	1, 322	231	1, 175	1, 406
33	355	3, 747	4, 102	360	4, 028	4, 388
34	238	1, 497	1, 735	241	1, 609	1, 850
35	148	2, 474	2, 622	150	2, 726	2, 876
37	289	4, 694	4, 983	293	5, 137	5, 430
38	202	5, 703	5, 905	205	6, 230	6, 435
Total	1, 900	24, 854	28, 342	1, 920	27, 064	30, 680
	1990					
17–F	....	....	1, 817			
25	440	6, 675	7, 115			
29	235	1, 260	1, 495			
33	365	4, 306	4, 671			
34	245	1, 723	1, 968			
35	152	2, 979	3, 131			
37	296	5, 591	5, 887			
38	208	6, 768	6, 976			
Total	1, 941	29, 302	33, 060			

TABLE 2

Energy for Load, Peak Demand, and Annual Load Factors for South Central Region (SCRAC)

Power supply area and region	Energy for load (million kwh)	Peak demand (mega-watts)	Annual load factors (percent)	Peak month	Energy for load (million kwh)	Peak demand (mega-watts)	Annual load factors (percent)	Peak month
	1965				**1966**			
17–F [1]	6, 479	1, 448	51. 1	July	6, 973	1, 614	49. 3	July
25	21, 049	4, 135	58. 1	July	23, 619	4, 781	56. 4	July
29	5, 235	1, 196	50. 0	July	5, 746	1, 270	51. 6	July
33	15, 833	3, 642	49. 6	July	17, 325	4, 025	49. 1	Aug.
34	7, 285	1, 570	53. 0	July	7, 877	1, 679	53. 6	July
35	13, 285	2, 344	64. 7	Aug.	14, 662	2, 679	62. 5	July
37	22, 633	4, 972	52. 0	July	25, 134	5, 621	51. 0	Aug.
38	26, 842	5, 297	57. 8	July	30, 229	5, 927	58. 2	Aug.
Non-coincidental Peak	118, 641	24, 604	55. 0	....	131, 565	27, 596	54. 4	....
Monthly Diversity Factor		(1. 0006)				(1. 0056)		
Coincidental Peak	118, 641	24, 589	55. 0	July	131, 565	27, 440	54. 7	July
	1970				**1975**			
17–F [1]	9, 380	2, 100	51. 0	July	12, 860	2, 850	51. 5	July
25	34, 340	7, 260	54. 0	Aug.	53, 130	11, 170	54. 3	Aug.
29	7, 710	1, 760	50. 0	July	10, 550	2, 400	50. 2	July
33	26, 540	6, 120	49. 5	Aug.	40, 840	9, 400	49. 6	Aug.
34	11, 200	2, 460	52. 0	Aug.	16, 200	3, 530	52. 5	Aug.
35	24, 000	4, 240	64. 5	Aug.	40, 600	7, 140	65. 0	Aug.
37	35, 600	7, 970	51. 0	Aug.	55, 300	12, 250	51. 5	Aug.
38	43, 600	8, 510	58. 5	Aug.	67, 700	13, 100	59. 0	Aug.
Non-coincidental Peak	192, 370	40, 420	54. 3	....	297, 180	61, 840	54. 9	....
Monthly Diversity Factor		(1. 0029)				(1. 0026)		
Coincidental Peak	192, 370	40, 301	54. 5	Aug.	297, 180	61, 678	55. 0	Aug.
	1980				**1985**			
17–F [1]	17, 580	3, 860	52. 0	July	24, 510	5, 330	52. 5	July
25	78, 440	16, 400	54. 6	Aug.	110, 610	23, 000	54. 9	Aug.
29	14, 350	3, 250	50. 4	July	19, 280	4, 350	50. 6	July
33	60, 080	13, 800	49. 7	Aug.	84, 630	19, 400	49. 8	Aug.
34	23, 000	4, 950	53. 0	Aug.	31, 800	6, 780	53. 5	Aug.
35	64, 500	11, 240	65. 5	Aug.	97, 700	16, 900	66. 0	Aug.
37	82, 000	18, 000	52. 0	Aug.	118, 600	25, 800	52. 5	Aug.
38	102, 680	19, 700	59. 5	Aug.	152, 425	29, 000	60. 0	Aug.
Non-coincidental Peak	442, 630	91, 200	55. 2	....	639, 555	130, 560	55. 9	....
Monthly Diversity Factor		(1. 0024)				(1. 0023)		
Coincidental Peak	442, 630	90, 980	55. 4	Aug.	639, 555	130, 259	56. 0	Aug.
	1990				**1990 [2]**			
17–F [1]	34, 080	7, 340	53. 0	July				
25	152, 300	31, 500	55. 2	Aug.				
29	25, 630	5, 760	50. 8	July				
33	116, 270	26, 600	49. 9	Aug.				
34	42, 900	9, 070	54. 0	Aug.				
35	141, 300	24, 250	66. 5	Aug.	197, 345	33, 879	66. 5	Aug.
37	168, 000	36, 200	53. 0	Aug.				
38	219, 900	41, 500	60. 2	Aug.				
Non-coincidental Peak	900, 380	182, 220	56. 4	....	956, 425	191, 489	56. 9	....
Monthly Diversity Factor		(1. 0022)				(1. 0022)		
Coincidental Peak	900, 380	181, 811	56. 5	Aug.	956, 425	191, 428	56. 8	Aug.

[1] Does not include portion of Iowa.

[2] The following higher load data was requested by Gulf States Utilities Company for PSA 35 in 1990 only.

TABLE 3

Classified Sales for South Central Region (SCRAC)

(Million kwh)

PSA and region	Farm, excluding irrigation and drainage pumping	Irrigation and drainage pumping	Nonfarm residential	Commercial	Industrial	Street and highway lighting	Electrified transportation	All other	Total to ultimate consumers	Losses	Energy for load
1965											
17-F [1].....	132	....	1, 501	1, 852	2, 362	....	....	632	6, 479	([2])	6, 479
25.........	440	122	5, 844	3, 807	7, 755	203	7	951	19, 129	1, 920	21, 049
29.........	446	17	1, 121	1, 289	1, 547	59	....	142	4, 621	614	5, 235
33.........	395	18	4, 258	3, 302	4, 994	135	....	1, 010	14, 112	1, 721	15, 833
34.........	320	4	1, 773	1, 419	2, 599	82	....	266	6, 463	822	7, 285
35.........	182	2	2, 741	1, 759	7, 382	73	....	271	12, 410	875	13, 285
37.........	328	73	6, 324	5, 780	7, 031	203	6	779	20, 524	2, 109	22, 633
38.........	266	138	6, 675	5, 684	11, 459	157	....	449	24, 828	2, 014	26, 842
Total..	2, 509	374	30, 237	24, 892	45, 129	912	13	4, 500	108, 566	10, 075	118, 641
1966											
17-F [1].....	135	....	1, 610	1, 963	2, 570	....	....	695	6, 973	([2])	6, 973
25.........	474	116	6, 558	4, 118	8, 953	216	7	1, 057	21, 499	2, 120	23, 619
29.........	482	19	1, 242	1, 455	1, 600	63	....	178	5, 039	707	5, 746
33.........	430	18	4, 639	3, 553	5, 535	137	....	1, 093	15, 405	1, 920	17, 325
34.........	340	1	1, 944	1, 546	2, 822	87	....	286	7, 026	851	7, 877
35.........	187	2	3, 056	1, 957	8, 117	79	....	296	13, 694	968	14, 662
37.........	344	67	6, 797	6, 328	8, 167	223	....	823	22, 749	2, 385	25, 134
38.........	278	123	7, 332	6, 328	13, 275	165	....	462	27, 963	2, 266	30, 229
Total..	2, 670	346	33, 178	27, 248	51, 039	970	7	4, 890	120, 348	11, 217	131, 565
1970											
17-F [1].....	150	....	2, 250	2, 680	3, 350	....	....	950	9, 380	([2])	9, 380
25.........	600	160	9, 700	6, 070	13, 000	340	....	1, 270	31, 140	3, 200	34, 340
29.........	575	42	1, 740	1, 800	2, 344	82	....	215	6, 798	912	7, 710
33.........	530	25	6, 750	5, 700	9, 392	193	....	1, 400	23, 990	2, 550	26, 540
34.........	417	4	2, 769	1, 947	4, 243	100	....	390	9, 870	1, 330	11, 200
35.........	250	3	5, 200	3, 200	12, 467	160	....	490	21, 770	2, 230	24, 000
37.........	503	96	10, 460	8, 500	11, 400	268	3	1, 070	32, 300	3, 300	35, 600
38.........	377	205	10, 500	8, 000	20, 268	300	....	800	40, 450	3, 150	43, 600
Total..	3, 402	535	49, 369	37, 897	76, 464	1, 443	3	6, 585	175, 698	16, 672	192, 370
1975											
17-F [1].....	160	....	3, 150	3, 500	4, 750	....	....	1, 300	12, 860	([2])	12, 860
25.........	812	198	14, 800	8, 970	21, 350	480	....	1, 720	48, 330	4, 800	53, 130
29.........	723	57	2, 400	2, 270	3, 507	103	....	285	9, 345	1, 205	10, 550
33.........	723	31	10, 100	9, 000	15, 298	248	....	1, 880	37, 280	3, 560	40, 840
34.........	525	5	4, 130	2, 540	6, 390	140	....	510	14, 240	1, 960	16, 200
35.........	330	4	8, 800	5, 200	21, 546	250	....	690	36, 820	3, 780	40, 600
37.........	687	108	16, 300	12, 100	19, 325	360	....	1, 420	50, 300	5, 000	55, 300
38.........	507	240	16, 800	11, 500	32, 163	470	....	1, 120	62, 800	4, 900	67, 700
Total..	4, 467	643	76, 480	55, 080	124, 329	2, 051	....	8, 925	271, 975	25, 205	297, 180

TABLE 3—Continued

(Million kwh)

PSA and region	Farm, excluding irrigation and drainage pumping	Irrigation and drainage pumping	Non-farm-residential	Commercial	Industrial	Street and highway lighting	Electrified transportation	All other	Total to ultimate consumers	Losses	Energy for load
					1980						
17–F [1]	165	...	4, 400	4, 700	6, 600	...	...	1, 715	17, 580	(2)	17, 580
25	1, 032	238	22, 000	12, 140	33, 000	630	...	2, 300	71, 340	7, 100	78, 440
29	882	70	3, 130	2, 760	5, 358	125	...	365	12, 690	1, 660	14, 350
33	980	37	14, 900	13, 600	22, 855	308	...	2, 450	55, 130	4, 950	60, 080
34	639	6	5, 995	3, 230	9, 570	180	...	630	20, 250	2, 750	23, 000
35	430	4	14, 000	7, 850	34, 971	345	...	900	58, 500	6, 000	64, 500
37	919	120	25, 500	16, 500	29, 366	485	...	1, 810	74, 700	7, 300	82, 000
38	652	280	26, 300	16, 400	49, 698	650	...	1, 450	95, 430	7, 250	102, 680
Total	5, 699	755	116, 225	77, 180	191, 418	2, 723	...	11, 620	405, 620	37, 010	442, 630
					1985						
17–F [1]	170	...	6, 290	6, 450	9, 300	...	...	2, 300	24, 510	(2)	24, 510
25	1, 304	281	32, 300	15, 840	47, 000	810	...	3, 020	100, 555	10, 055	110, 610
29	1, 048	85	3, 940	3, 260	8, 172	148	...	450	17, 103	2, 177	19, 280
33	1, 287	44	20, 900	19, 300	33, 099	370	...	3, 080	78, 080	6, 550	84, 630
34	763	7	8, 015	4, 000	14, 400	225	...	750	28, 160	3, 640	31, 800
35	540	5	21, 200	11, 450	53, 825	450	...	1, 130	88, 600	9, 100	97, 700
37	1, 178	132	37, 800	21, 000	45, 265	615	...	2, 210	108, 200	10, 400	118, 600
38	812	315	40, 600	22, 300	75, 038	825	...	1, 760	141, 650	10, 775	152, 425
Total	7, 102	869	171, 045	103, 600	286, 099	3, 443	...	14, 700	586, 858	52, 697	639, 555
					1990						
17–F [1]	175	...	9, 000	8, 900	13, 000	...	...	3, 005	34, 080	(2)	34, 080
25	1, 580	325	48, 000	19, 725	64, 000	1, 040	...	4, 130	138, 800	13, 500	152, 300
29	1, 260	100	4, 775	3, 770	12, 215	175	...	550	22, 845	2, 785	25, 630
33	1, 614	50	27, 600	25, 800	48, 736	450	...	3, 720	107, 970	8, 300	116, 270
34	882	8	10, 425	4, 840	21, 030	275	...	870	38, 330	4, 570	42, 900
35	660	5	29, 660	16, 200	79, 650	575	...	1, 400	128, 150	13, 150	141, 300
37	1, 452	146	53, 500	26, 000	68, 912	750	...	2, 640	153, 400	14, 600	168, 000
38	990	350	59, 800	29, 000	111, 420	1, 000	...	2, 040	204, 600	15, 300	219, 900
Total	8, 613	984	242, 760	134, 235	418, 963	4, 265	...	18, 355	828, 175	72, 205	900, 380

[1] Does not include part in Iowa.

[2] Losses are included in total to ultimate consumer.

TABLE 4

Average Annual Use of Farm, Nonfarm-Residential and Commercial Customers for South Central Region (SCRAC)

PSA and region	Farm, excluding irrigation and drainage pumping			Nonfarm-residential			Commercial		
	Average number of customers	Kwh per customer	Total consumption (million kwh)	Average number of customers	Kwh per customer	Total consumption (million kwh)	Average number of customers	Kwh per customer	Total consumption (million kwh)
					1965				
17–F [1]	24, 366	5, 435	132	363, 810	4, 124	1, 501	49, 301	37, 562	1, 852
25	124, 930	3, 522	440	1, 224, 225	4, 773	5, 844	164, 097	23, 200	3, 807
29	68, 555	6, 507	446	286, 804	3, 909	1, 121	55, 071	23, 406	1, 289
33	110, 740	3, 573	395	999, 419	4, 303	4, 258	137, 996	23, 928	3, 302
34	73, 790	4, 332	320	440, 170	4, 028	1, 773	67, 560	21, 004	1, 419
35	44, 345	4, 109	182	521, 086	5, 393	2, 741	66, 655	26, 390	1, 759
37	87, 615	3, 746	328	1, 168, 064	5, 414	6, 324	185, 074	31, 229	5, 780
38	56, 496	4, 697	266	1, 100, 701	6, 065	6, 675	164, 532	34, 546	5, 684
South Central Region	590, 837	4, 247	2, 509	6, 104, 279	4, 953	30, 237	890, 286	27, 959	24, 892
					1966				
17–F [1]	24, 200	5, 578	135	379, 770	4, 239	1, 610	49, 667	39, 523	1, 963
25	123, 480	3, 839	474	1, 248, 981	5, 250	6, 558	166, 756	24, 695	4, 118
29	68, 062	7, 079	482	291, 387	4, 265	1, 242	55, 048	26, 430	1, 455
33	108, 780	3, 950	430	1, 017, 974	4, 557	4, 639	140, 274	25, 329	3, 553
34	73, 010	4, 657	340	447, 628	4, 344	1, 944	66, 789	23, 147	1, 546
35	43, 610	4, 297	187	537, 800	5, 683	3, 056	68, 880	28, 412	1, 957
37	86, 130	3, 994	344	1, 189, 617	5, 714	6, 797	191, 427	33, 057	6, 328
38	56, 155	4, 957	278	1, 134, 805	6, 460	7, 332	167, 512	37, 776	6, 328
South Central Region	583, 427	4, 576	2, 670	6, 247, 962	5, 310	33, 178	906, 353	30, 063	27, 248
					1970				
South Central Region	545, 170	6, 240	3, 402	7, 052, 700	7, 000	49, 369	972, 500	38, 970	37, 897
					1975				
South Central Region	528, 250	8, 460	4, 467	8, 179, 700	9, 350	76, 480	1, 063, 700	51, 780	55, 080
					1980				
South Central Region	523, 460	10, 890	5, 699	9, 553, 000	12, 170	116, 225	1, 156, 800	66, 720	77, 180
					1985				
South Central Region	521, 910	13, 610	7, 102	11, 179, 400	15, 300	171, 045	1, 251, 300	82, 790	103, 600
					1990				
South Central Region	521, 220	16, 520	8, 613	13, 115, 000	18, 510	242, 760	1, 347, 300	99, 630	134, 235

[1] Does not include portion in Iowa.

TABLE 5

South Central Region (SCRAC) Monthly Load Characteristics and Requirements

	Energy for load (million kwh)	Peak demand (megawatts)	Load factor (percent)	Energy for load (million kwh)	Peak demand (megawatts)	Load factor (percent)
	1960			1965		
Jan	5, 586	10, 415	72. 1	8, 458	14, 862	76. 5
Feb	5, 280	10, 317	73. 5	7, 853	15, 111	77. 3
Mar	5, 638	10, 321	73. 4	8, 535	15, 261	75. 2
Apr	5, 409	10, 584	71. 0	8, 761	16, 721	72. 8
May	6, 029	12, 459	65. 0	9, 597	18, 671	69. 1
June	7, 189	15, 032	66. 4	11, 073	22, 498	68. 4
July	7, 925	[1] 15, 982	66. 6	13, 044	[1] 24, 589	71. 3
Aug	8, 064	15, 800	68. 6	12, 630	24, 203	70. 1
Sept	7, 086	15, 278	64. 4	11, 189	23, 862	65. 1
Oct	6, 250	12, 881	65. 2	9, 274	17, 880	69. 7
Nov	5, 664	11, 336	69. 4	8, 940	16, 591	74. 8
Dec	5, 951	11, 428	70. 0	9, 287	16, 787	74. 4
Region	76, 071	[1] 15, 982	54. 3	118, 641	[1] 24, 589	55. 1
	1966			1970		
Jan	9, 647	16, 668	77. 8	14, 108	25, 606	74. 1
Feb	8, 770	16, 352	79. 8	12, 789	25, 311	75. 2
Mar	9, 385	16, 089	78. 4	13, 903	25, 228	74. 1
Apr	9, 449	17, 562	74. 7	13, 810	27, 281	70. 3
May	10, 746	21, 730	66. 5	15, 859	32, 116	66. 4
June	12, 251	24, 758	68. 7	17, 691	36, 614	67. 1
July	15, 011	[1] 27, 440	73. 5	20, 388	39, 370	69. 6
Aug	13, 767	26, 907	68. 8	20, 672	[1] 40, 301	68. 9
Sept	11, 756	23, 699	68. 9	17, 787	37, 771	65. 4
Oct	10, 432	20, 936	67. 0	15, 647	31, 248	67. 3
Nov	9, 935	18, 184	75. 9	14, 552	28, 023	72. 1
Dec	10, 416	18, 469	75. 8	15, 164	28, 036	72. 7
Region	131, 565	[1] 27, 440	54. 7	192, 370	[1] 40, 301	54. 5

See footnote at end of table.

TABLE 5—Continued

	Energy for load (million kwh)	Peak demand (megawatts)	Load factor (percent)	Energy for load (million kwh)	Peak demand (megawatts)	Load factor (percent)
	1975			1980		
Jan	21, 759	39, 144	74. 7	32, 367	57, 708	75. 4
Feb	19, 727	38, 701	75. 8	29, 346	57, 059	73. 9
Mar	21, 450	38, 577	74. 7	31, 921	56, 890	75. 4
Apr	21, 327	41, 799	70. 9	31, 763	61, 730	71. 5
May	24, 519	49, 215	67. 0	36, 549	72, 684	67. 6
June	27, 359	56, 048	67. 8	40, 777	82, 699	68. 5
July	31, 498	60, 222	70. 3	46, 916	88, 757	71. 0
Aug	31, 954	[1] 61, 678	69. 6	47, 611	[1] 90, 980	70. 3
Sept	27, 524	57, 861	66. 1	41, 044	85, 420	66. 7
Oct	24, 190	47, 921	67. 8	36, 047	70, 815	68. 4
Nov	22, 474	42, 887	72. 8	33, 465	63, 286	73. 4
Dec	23, 399	42, 799	73. 5	34, 824	63, 045	74. 2
Region	297, 180	[1] 61, 678	55. 0	442, 630	[1] 90, 980	55. 4
	1985			1990		
Jan	46, 710	82, 593	76. 0	65, 691	115, 231	76. 6
Feb	42, 350	81, 661	77. 2	59, 562	113, 922	77. 8
Mar	46, 087	81, 453	76. 0	64, 844	113, 680	76. 7
Apr	45, 893	88, 491	72. 0	64, 610	123, 623	72. 6
May	52, 850	104, 182	68. 2	74, 445	145, 542	68. 7
June	58, 963	118, 440	69. 1	83, 063	165, 358	69. 8
July	67, 814	127, 067	71. 7	95, 511	177, 351	72. 4
Aug	68, 809	[1] 130, 259	71. 0	96, 902	[1] 181, 811	71. 6
Sept	59, 358	122, 402	67. 4	83, 627	170, 957	67. 9
Oct	52, 105	101, 554	69. 0	73, 371	141, 908	69. 5
Nov	48, 338	90, 659	74. 1	68, 022	126, 582	74. 6
Dec	50, 278	90, 167	74. 9	70, 732	125, 711	75. 6
Region	639, 555	[1] 130, 259	56. 0	900, 380	[1] 181, 811	56. 5

[1] Coincidental annual peak.

TABLE 6

South Central Region.—Tabulation of Monthly Energy and Monthly Maximum Peaks for Summer and Winter Periods [1] for Years 1965 Through 1990

Year [2]	Monthly energy for load (million kwh)	Monthly maximum peak demand (megawatts)	Monthly load factor (percent)	Peak month
PSA 17–F (Less Iowa) Summer Load:				
1965	674	1, 448	62. 6	July
1966	781	1, 614	65. 0	July
1970	976	2, 100	62. 4	July
1975	1, 337	2, 850	63. 1	July
1980	1, 828	3, 860	63. 6	July
1985	2, 549	5, 330	64. 2	July
1990	3, 545	7, 340	64. 9	July
PSA 17–F (Less Iowa) Winter Load:				
1965	538	1, 057	68. 4	December
1966	572	1, 106	69. 5	December
1970	779	1, 533	68. 3	December
1975	1, 067	2, 080	68. 9	December
1980	1, 459	2, 818	69. 6	December
1985	2, 034	3, 890	70. 3	December
1990	2, 829	5, 358	70. 9	December
PSA 25 Summer Load:				
1965	2, 326	4, 135	75. 6	July
1966	2, 709	4, 781	76. 1	July
1970	3, 640	7, 260	67. 4	August
1975	5, 631	11, 170	67. 8	August
1980	8, 315	16, 400	68. 1	August
1985	11, 725	23, 000	68. 5	August
1990	16, 144	31, 500	68. 9	August
PSA 25 Winter Load:				
1965	1, 716	2, 890	79. 8	January [3]
1966	1, 868	3, 152	79. 6	December
1970	2, 713	4, 680	77. 9	December
1975	4, 197	7, 140	79. 0	December
1980	6, 197	10, 410	80. 0	December
1985	8, 738	14, 490	81. 1	December
1990	12, 032	19, 700	82. 1	December
PSA 29 Summer Load:				
1965	529	1, 196	59. 4	July
1966	658	1, 270	69. 6	July
1970	794	1, 760	60. 6	July
1975	1, 089	2, 400	60. 9	July
1980	1, 478	3, 250	61. 1	July
1985	1, 986	4, 350	61. 4	July
1990	2, 640	5, 760	61. 6	July
PSA 29 Winter Load:				
1965	454	873	69. 9	December
1966	503	877	77. 1	December
1970	673	1, 355	66. 8	December
1975	921	1, 850	66. 9	December
1980	1, 252	2, 500	67. 3	December
1985	1, 683	3, 350	67. 5	December
1990	2, 237	4, 435	67. 8	December

See footnotes at end of table.

TABLE 6—Continued

Year[2]	Monthly energy for load (million kwh)	Monthly maximum peak demand (megawatts)	Monthly load factor (percent)	Peak month
PSA 33 Summer Load:				
1965	1, 787	3, 642	65. 9	July
1966	2, 093	3, 977	70. 7	July
1970	2, 866	6, 120	62. 9	August
1975	4, 411	9, 400	63. 1	August
1980	6, 489	13, 800	63. 2	August
1985	9, 140	19, 400	63. 3	August
1990	12, 557	26, 600	63. 4	August
PSA 33 Winter Load:				
1965	1, 310	2, 355	74. 8	January [3]
1966	1, 417	2, 582	73. 7	December
1970	2, 150	4, 223	68. 4	December
1975	3, 308	6, 486	68. 6	December
1980	4, 866	9, 522	68. 7	December
1985	6, 855	13, 386	68. 8	December
1990	9, 418	18, 354	69. 0	December
PSA 34 Summer Load:				
1965	730	1, 570	62. 5	July
1966	875	1, 679	70. 0	July
1970	1, 163	2, 460	63. 5	August
1975	1, 685	3, 530	64. 1	August
1980	2, 392	4, 950	65. 0	August
1985	3, 306	6, 780	65. 5	August
1990	4, 461	9, 070	66. 1	August
PSA 34 Winter Load:				
1965	613	1, 185	69. 5	December
1966	679	1, 200	76. 0	December
1970	953	1, 780	72. 0	December
1975	1, 377	2, 500	74. 0	December
1980	1, 957	3, 460	76. 0	December
1985	2, 706	4, 660	78. 0	December
1990	3, 651	6, 130	80. 0	December
PSA 35 Summer Load[4]:				
1965	1, 347	2, 344	77. 2	August
1966	1, 542	2, 679	77. 4	July
1970	2, 448	4, 240	77. 6	August
1975	4, 141	7, 140	78. 0	August
1980	6, 579	11, 240	78. 7	August
1985	9, 966	16, 900	79. 3	August
1990	14, 413	24, 250	79. 9	August
PSA 35 Winter Load[5]:				
1965	1, 111	1, 794	83. 0	January [3]
1966	1, 160	1, 925	81. 0	December
1970	1, 920	3, 265	79. 0	December
1975	3, 248	5, 498	79. 4	December
1980	5, 160	8, 655	80. 1	December
1985	7, 816	13, 013	80. 7	December
1990	11, 304	18, 672	81. 4	December
PSA 37 Summer Load:				
1965	2, 689	4, 972	72. 7	July
1966	2, 786	5, 621	66. 6	August
1970	4, 094	7, 970	69. 0	August
1975	6, 359	12, 250	69. 8	August
1980	9, 430	18, 000	70. 4	August
1985	13, 639	25, 800	71. 1	August
1990	19, 320	36, 200	71. 7	August

See footnotes at end of table.

TABLE 6—Continued

Year [2]	Monthly energy for load (million kwh)	Monthly maximum peak demand (megawatts)	Monthly load factor (percent)	Peak month
PSA 37 Winter Load:				
1965	1, 708	3, 164	72. 6	December
1966	1, 941	3, 457	75. 4	December
1970	2, 706	5, 260	69. 1	December
1975	4, 203	8, 085	69. 9	December
1980	6, 232	11, 880	70. 5	December
1985	9, 014	17, 028	71. 2	December
1990	12, 768	23, 892	71. 8	December
PSA 38 Summer Load:				
1965	2, 914	5, 297	73. 9	July
1966	3, 305	5, 927	74. 9	August
1970	4, 796	8, 510	75. 7	August
1975	7, 447	13, 100	76. 4	August
1980	11, 295	19, 700	77. 1	August
1985	16, 767	29, 000	77. 7	August
1990	24, 189	41, 500	78. 3	August
PSA 38 Winter Load:				
1965	1, 987	3, 767	73. 3	November
1966	2, 249	4, 240	73. 6	November
1970	3, 183	6, 127	72. 2	November
1975	4, 942	9, 432	72. 8	November
1980	7, 496	14, 184	73. 4	November
1985	11, 127	20, 880	74. 0	November
1990	16, 052	29, 880	74. 6	November
South Central Region (SCRAC) Summer Load [6]				
1965	13, 017	24, 589	71. 1	July
1966	15, 010	27, 440	73. 5	July
1970	20, 672	40, 301	68. 9	August
1975	31, 954	61, 678	69. 6	August
1980	47, 611	90, 980	70. 3	August
1985	68, 809	130, 259	71. 0	August
1990	96, 902	181, 811	71. 6	August
South Central Region (SCRAC) Winter Load [7]				
1965	9, 287	16, 787	74. 4	December
1966	10, 415	18, 469	75. 8	December
1970	15, 164	28, 036	72. 8	December
1975	23, 399	42, 799	73. 6	December
1980	34, 824	63, 045	74. 3	December
1985	50, 278	90, 167	75. 0	December
1990	70, 732	125, 711	75. 7	December

[1] Summer period includes months of June, July, August and September; winter period includes months of November, December, January, and February.

[2] 1965 and 1966 data are actual; all other data are estimated.

[3] 1966.

[4] Gulf States Utilities Company requested the following higher summer peak load data: year, 1990; monthly energy for load (million kwh) 20,124; monthly maximum peak demand (megawatts) 33,879; monthly load factor (percent) 79.9; peak month, August.

[5] Gulf States Utilities Company requested the following higher winter peak load data: year, 1990; monthly energy for load (million kwh) 15,496; monthly maximum peak demand (megawatts) 26,087; monthly load factor (percent) 81.4; peak month, December.

[6] Gulf States Utilities Company's request for higher summer load data in PSA 35 raises the regional totals as follows: year, 1990; monthly energy for load (million kwh) 102,613; monthly maximum peak demand (megawatts) 191, 440; monthly load factor (percent) 71.6; peak month, August.

[7] Gulf States Utilities Company's request for higher winter load data in PSA 35 raises the regional totals as follows: year 1990; monthly energy for load (million kwh) 74,924; monthly maximum peak demand (megawatts) 133,126; monthly load factor (percent) 75.7; peak month, December.

TABLE 7

Summer and Winter Peak Loads and Seasonal Differences for Two Groups of Power Supply Areas in the South Central Region, 1965–1990

[Megawatts]

Year [1]	Summer peak load	Winter peak load	Seasonal differences [2]	Annual peak season
For PSA's 37 and 38 Combined:				
1965	[3] 10, 269	[4] 6, 847	3, 422	Summer
1966	[5] 11, 548	[4] 7, 659	3, 889	Summer
1970	16, 480	11, 387	5, 093	Summer
1975	25, 350	17, 517	7, 833	Summer
1980	37, 700	26, 064	11, 636	Summer
1985	54, 800	37, 908	16, 892	Summer
1990	77, 700	53, 772	23, 928	Summer
For PSA's 17–F, 25, 29, 33, 34, and 35 Combined:				
1965	[3] 14, 320	[6] 10, 058	4, 262	Summer
1966	[3] 16, 000	[6] 10, 842	5, 158	Summer
1970	23, 821	16, 649	7, 172	Summer
1975	36, 328	25, 282	11, 046	Summer
1980	53, 280	36, 981	16, 299	Summer
1985	75, 459	52, 259	23, 200	Summer
1990	104, 111	71, 939	32, 172	Summer
For South Central Region (SCRAC):				
1965	[3] 24, 589	[6] 16, 787	7, 802	Summer
1966	[3] 27, 440	[6] 18, 469	8, 971	Summer
1970	40, 301	28, 036	12, 265	Summer
1975	61, 678	42, 799	18, 879	Summer
1980	90, 980	63, 045	27, 935	Summer
1985	130, 259	90, 167	40, 092	Summer
1990	181, 811	125, 711	56, 100	Summer

[1] 1965 and 1966 data are actual; all other years estimated.
[2] Due to coincident seasonal demand.
[3] Peak occurred in July.
[4] Peak occurred in November.
[5] Peak occurred in August.
[6] Peak occurred in December.

TABLE 8

Electric Load Centers in South Central Region

Load center	Net energy (Million kwh)	Peak demand (mw)	Load factor (Percent)
		[1966 Data]	
PSA 25:			
Brookhaven	470. 5	93. 0	57. 8
Houma	377. 2	76. 5	56. 3
Greenville	638. 0	140. 1	52. 0
Winona	638. 0	140. 0	52. 0
Vicksburg	413. 2	87. 3	54. 0
New Orleans	7, 542. 9	1, 536. 0	56. 1
Monroe	1, 672. 3	404. 1	47. 2
Clarksdale	556. 6	122. 2	52. 0
Jackson	1, 175. 7	232. 6	57. 7
Natchez	359. 5	76. 0	54. 0
Little Rock	1, 758. 0	334. 5	60. 0
Hot Springs	3, 042. 8	453. 1	76. 7
Pine Bluff	1, 095. 9	221. 7	56. 4
El Dorado	909. 5	185. 9	55. 8
West Memphis	699. 4	153. 5	52. 0
Paragould	571. 9	136. 0	48. 0
Newport	536. 4	120. 1	51. 0
Poplar Bluff	587. 6	139. 7	50. 0
Unassigned	563. 7	128. 7	50. 0
PSA total	23, 609. 1	4, 781. 0	56. 4
PSA 29:			
Topeka	2, 200. 5	439. 8	57. 1
Manhattan	445. 1	111. 8	45. 4
Salina	572. 8	142. 6	45. 9
Hutchinson	719. 7	202. 9	40. 5
Garden City	728. 1	118. 5	70. 1
Hays	993. 2	229. 4	49. 4
Unassigned	86. 2	25. 0	39. 4
PSA total	5, 745. 6	1, 270. 0	51. 6
PSA 33:			
Tulsa	2, 630. 1	703. 9	42. 7
Vinita	1, 272. 0	249. 7	58. 2
Bartlesville	589. 3	122. 3	55. 0
McAlester	881. 3	211. 1	47. 7
Enid	1, 044. 2	251. 3	47. 4
Oklahoma City	4, 055. 0	810. 1	57. 1
Lawton	1, 247. 3	283. 6	50. 2
Ardmore	1, 014. 0	213. 2	54. 3
Fayetteville	482. 8	112. 0	49. 2
Fort Smith	552. 0	126. 6	49. 8
Texarkana	548. 6	145. 6	43. 0
Longview	1, 243. 8	317. 5	44. 7
Shreveport	1, 310. 1	339. 8	44. 0
Unassigned	454. 4	138. 3	37. 5
PSA total	17, 324. 9	4, 025. 0	49. 1

TABLE 8—Continued

Load center	Net energy (Million kwh)	Peak demand (mw)	Load factor (Percent)
	[1966 Data]		
PSA 34:			
Wichita	3, 068. 5	662. 1	52. 9
Chanute	878. 3	167. 8	59. 8
Springfield	2, 687. 7	547. 8	56. 0
Warrenburg	1, 042. 9	250. 6	47. 5
Unassigned	199. 8	50. 7	45. 0
PSA total	7, 877. 2	1, 679. 0	53. 6
PSA 35:			
Bryan	808. 4	161. 9	57. 0
Beaumont	2, 856. 2	506. 6	64. 4
Port Arthur	1, 494. 3	262. 4	65. 0
Lake Charles	2, 534. 9	445. 2	65. 0
Baton Rouge	5, 209. 0	881. 9	67. 4
Alexandria	1, 604. 8	385. 7	47. 5
Unassigned	154. 8	35. 3	50. 0
PSA total	14, 662. 4	2, 679. 0	62. 5
PSA 37:			
Dallas	7, 788. 4	1, 932. 8	46. 0
Fort Worth	3, 687. 9	956. 8	44. 0
Denton	385. 1	101. 4	43. 4
Paris	526. 0	129. 6	46. 3
Sherman	736. 3	171. 8	48. 9
Stephenville	467. 0	123. 3	43. 2
Tyler	620. 0	138. 8	51. 0
Lufkin	669. 7	127. 4	60. 0
Palestine	668. 8	165. 9	46. 0
Waco	1, 018. 5	212. 5	54. 7
Temple	559. 7	120. 4	49. 0
Taylor	632. 7	123. 8	58. 3
Wichita Falls	1, 055. 9	219. 8	54. 8
Abilene	1, 221. 8	240. 5	58. 0
San Angelo	601. 3	129. 5	53. 0
Odessa	3, 112. 1	493. 4	72. 0
Big Spring	1, 194. 2	179. 3	76. 0
Unassigned	189. 1	54. 0	40. 0
PSA total	25, 134. 5	5, 621. 0	51. 0
PSA 38:			
Houston	18, 259. 4	3, 338. 4	62. 4
Austin	2, 803. 0	621. 3	51. 5
San Antonio	3, 091. 2	759. 0	46. 5
Victoria	1, 956. 0	366. 0	61. 0
Corpus Christi	2, 257. 2	440. 5	58. 5
Harlingen	1, 011. 9	230. 6	50. 1
Laredo	786. 6	154. 8	58. 0
Unassigned	63. 5	16. 4	44. 2
PSA total	30, 228. 8	5, 927. 0	58. 2
PSA 17–F (Less Iowa):			
Kansas City	7, 078. 0	1, 664. 0	48. 6

TABLE 8—Continued

Load center	Net energy (Million kwh)	Peak demand (mw)	Load factor (Percent)
	1970 Estimates		
PSA 25:			
Brookhaven	760	160	54. 2
Houma	580	140	47. 3
Greenville	815	190	48. 9
Winona	815	190	48. 9
Vicksburg	580	130	50. 9
New Orleans	11, 900	2, 490	54. 6
Monroe	2, 500	640	44. 8
Clarksdale	740	170	49. 0
Jackson	1, 840	390	53. 9
Natchez	500	110	51. 9
Little Rock	2, 530	520	54. 0
Hot Springs	4, 300	660	74. 0
Pine Bluff	1, 400	290	55. 1
El Dorado	1, 160	250	52. 5
West Memphis	960	220	50. 0
Paragould	620	150	46. 0
Newport	740	170	49. 0
Poplar Bluff	750	190	45. 1
Unassigned	850	200	48. 0
PSA total	34, 340	7, 260	54. 0
PSA 29:			
Topeka	2, 900	610	54. 3
Manhattan	580	150	44. 0
Salina	710	175	46. 3
Hutchinson	960	270	40. 0
Garden City	1, 070	180	67. 9
Hays	1, 350	330	47. 0
Unassigned	140	45	35. 5
PSA total	7, 710	1, 760	50. 0
PSA 33:			
Tulsa	3, 970	1, 030	44. 0
Vinita	1, 930	380	58. 6
Bartlesville	720	150	54. 8
McAlester	1, 340	320	48. 1
Enid	1, 650	390	48. 1
Oklahoma City	6, 610	1, 340	56. 3
Lawton	2, 110	480	50. 5
Ardmore	1, 390	290	54. 3
Fayetteville	770	180	49. 6
Fort Smith	830	190	50. 0
Texarkana	830	220	43. 4
Longview	1, 980	500	45. 0
Shreveport	1, 860	480	44. 5
Unassigned	550	170	38. 0
PSA total	26, 540	6, 120	49. 5

TABLE 8—Continued

Load center	Net energy (Million kwh)	Peak demand (mw)	Load factor (Percent)
	[1970 Estimates]		
PSA 34:			
Wichita	4, 100	910	51. 3
Chanute	1, 250	250	58. 2
Springfield	4, 090	860	54. 4
Warrensburg	1, 520	380	45. 9
Unassigned	240	60	44. 0
PSA total	11, 200	2, 460	52. 0
PSA 35:			
Bryan	1, 260	240	59. 0
Beaumont	5, 150	880	66. 5
Port Arthur	2, 190	370	67. 0
Lake Charles	3, 590	610	67. 0
Baton Rouge	8, 790	1, 450	69. 0
Alexandria	2, 840	650	49. 5
Unassigned	180	40	51. 0
PSA total	24, 000	4, 240	64. 6
PSA 37:			
Dallas	11, 000	2, 730	46. 0
Fort Worth	4, 910	1, 270	44. 0
Denton	590	160	43. 4
Paris	900	220	46. 5
Sherman	1, 010	240	49. 0
Stephenville	690	180	43. 5
Tyler	890	200	51. 5
Lufkin	1, 080	210	60. 0
Palestine	1, 030	260	46. 0
Waco	1, 410	290	54. 7
Temple	810	190	49. 0
Taylor	1, 000	200	58. 3
Wichita Falls	1, 420	300	54. 8
Abilene	1, 590	310	58. 0
San Angelo	800	170	53. 0
Odessa	4, 580	730	72. 0
Big Spring	1, 670	250	76. 0
Unassigned	220	60	40. 0
PSA total	35, 600	7, 970	51. 0
PSA 38:			
Houston	26, 900	4, 920	62. 4
Austin	4, 000	890	51. 5
San Antonio	4, 250	1, 040	46. 8
Victoria	2, 900	540	61. 3
Corpus Christi	3, 100	600	58. 8
Harlingen	1, 160	260	50. 4
Laredo	1, 170	230	58. 3
Unassigned	120	30	44. 5
PSA total	43, 600	8, 510	58. 5
PSA 17–F (Less Iowa):			
Kansas City	9, 380	2, 100	51. 0

TABLE 8—Continued

Load center	Net energy (Million kwh)	Peak demand (mw)	Load factor (Percent)
	1980 Estimates		
PSA 25:			
Brookhaven	1, 430	300	54. 4
Houma	1, 520	320	54. 2
Greenville	1, 570	360	49. 8
Winona	1, 570	360	49. 8
Vicksburg	1, 360	300	51. 8
New Orleans	30, 000	6, 180	55. 4
Monroe	4, 920	1, 240	45. 4
Clarksdale	1, 800	420	49. 5
Jackson	6, 360	1, 330	54. 6
Natchez	1, 090	240	51. 8
Little Rock	5, 980	1, 250	54. 8
Hot Springs	8, 710	1, 330	75. 0
Pine Bluffs	2, 280	500	52. 1
El Dorado	1, 990	430	53. 0
West Memphis	2, 080	470	50. 5
Paragould	760	190	46. 5
Newport	1, 510	350	49. 5
Poplar Bluff	1, 310	310	49. 0
Unassigned	2, 200	520	48. 5
PSA total	78, 440	16, 400	54. 6
PSA 29:			
Topeka	5, 190	1, 100	53. 9
Manhattan	1, 080	280	44. 4
Salina	1, 020	260	44. 7
Hutchinson	1, 790	510	40. 2
Garden City	2, 330	400	66. 5
Hays	2, 580	600	47. 0
Unassigned	360	100	39. 4
PSA total	14, 350	3, 250	50. 4
PSA 33:			
Tulsa	8, 580	2, 170	45. 1
Vinita	3, 790	760	56. 9
Bartlesville	1, 200	280	48. 9
McAlester	3, 470	820	48. 3
Enid	3, 680	870	48. 3
Oklahoma City	16, 800	3, 320	57. 8
Lawton	5, 320	1, 240	50. 0
Ardmore	2, 830	610	53. 0
Fayetteville	2, 000	460	49. 6
Fort Smith	1, 930	440	50. 0
Texarkana	2, 110	550	43. 8
Longview	4, 360	1, 190	41. 8
Shreveport	3, 240	860	43. 0
Unassigned	770	230	38. 2
PSA total	60, 080	13, 800	49. 7

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TABLE 8—Continued

Load center	Net energy (Million kwh)	Peak demand (mw)	Load factor (Percent)
	[1980 Estimates]		
PSA 34:			
Wichita	7, 380	1, 610	52. 3
Chanute	2, 370	460	58. 7
Springfield	9, 950	2, 060	54. 9
Warrensburg	2, 950	730	45. 9
Unassigned	350	90	44. 0
PSA total	23, 000	4, 950	53. 0
PSA 35:			
Bryan	3, 220	620	59. 5
Beaumont	16, 740	2, 790	68. 2
Port Arthur	4, 780	790	68. 5
Lake Charles	7, 300	1, 210	68. 5
Baton Rouge	23, 400	3, 780	70. 5
Alexandria	8, 810	1, 990	50. 5
Unassigned	250	60	51. 5
PSA total	64, 500	11, 240	65. 5
PSA 37:			
Dallas	25, 100	6, 160	46. 5
Fort Worth	9, 440	2, 410	44. 7
Denton	1, 610	410	44. 4
Paris	3, 020	730	47. 5
Sherman	2, 240	510	50. 0
Stephenville	1, 730	440	44. 5
Tyler	2, 150	470	52. 5
Lufkin	3, 460	650	60. 5
Palestine	2, 990	730	47. 0
Waco	3, 190	650	55. 7
Temple	1, 990	450	50. 0
Taylor	2, 800	540	59. 3
Wichita Falls	2, 820	580	55. 8
Abilene	2, 930	570	59. 0
San Angelo	1, 570	330	54. 0
Odessa	10, 900	1, 720	72. 5
Big Spring	3, 690	550	76. 5
Unassigned	370	100	41. 0
PSA total	82, 000	18, 000	52. 0
PSA 38:			
Houston	66, 900	12, 120	63. 0
Austin	9, 200	2, 010	52. 2
San Antonio	8, 990	2, 160	47. 5
Victoria	6, 840	1, 260	62. 0
Corpus Christi	6, 430	1, 240	59. 5
Harlingen	1, 600	360	51. 0
Loredo	2, 310	450	58. 7
Unassigned	410	100	45. 0
PSA total	102, 680	19, 700	59. 5
PSA 17–F (Less Iowa):			
Kansas City	17, 580	3, 860	52. 0

TABLE 8—Continued

Load center	Net energy (Million kwh)	Peak demand (mw)	Load factor (Percent)
	1990 Estimates		
PSA 25:			
Brookhaven	2, 920	600	55. 6
Houma	4, 400	900	55. 8
Greenville	2, 870	650	50. 4
Winona	2, 870	650	50. 4
Vicksburg	3, 030	660	52. 4
New Orleans	56, 740	11, 600	55. 8
Monroe	10, 600	2, 630	46. 0
Clarksdale	3, 350	760	50. 0
Jackson	17, 080	3, 510	55. 5
Natchez	1, 840	400	52. 5
Little Rock	12, 300	2, 520	55. 8
Hot Springs	14, 500	2, 180	76. 0
Pine Bluff	3, 200	730	50. 0
El Dorado	2, 910	620	53. 3
West Memphis	3, 760	790	51. 0
Paragould	920	220	46. 9
Newport	2, 590	590	49. 9
Poplar Bluff	2, 000	460	49. 5
Unassigned	4, 420	1, 030	48. 9
PSA total	152, 300	31, 500	55. 2
PSA 29:			
Topeka	9, 060	1, 870	55. 5
Manhattan	1, 820	470	44. 5
Salina	1, 460	370	45. 0
Hutchinson	3, 250	930	40. 0
Garden City	4, 900	840	66. 5
Hays	4, 400	1, 070	47. 0
Unassigned	740	210	39. 5
PSA total	25, 630	5, 760	50. 8
PSA 33:			
Tulsa	15, 950	4, 040	45. 1
Vinita	6, 710	1, 350	56. 9
Bartlesville	1, 880	500	42. 9
McAlester	7, 150	1, 550	52. 6
Enid	7, 200	1, 700	48. 3
Oklahoma City	33, 860	6, 780	57. 0
Lawton	11, 300	2, 580	50. 0
Ardmore	5, 390	1, 170	52. 6
Fayetteville	4, 000	920	49. 6
Fort Smith	3, 120	710	50. 0
Texarkana	4, 460	1, 180	43. 1
Longview	8, 500	2, 260	42. 9
Shreveport	5, 850	1, 560	42. 8
Unassigned	900	300	34. 2
PSA total	116, 270	26, 600	49. 9

TABLE 8—Continued

Load center	Net energy (Million kwh)	Peak demand (mw)	Load factor (Percent)
		[1990 Estimates]	
PSA 34:			
Wichita	12, 400	2, 650	53. 4
Chanute	3, 700	710	59. 2
Springfield	21, 560	4, 410	55. 9
Warrensburg	4, 790	1, 180	46. 4
Unassigned	450	120	44. 5
PSA total	42, 900	9, 070	54. 0
PSA 35*:			
Bryan	6, 230	1, 190	60. 0
Beaumont	37, 800	6, 250	69. 0
Port Arthur	8, 590	1, 420	69. 2
Lake Charles	14, 650	2, 420	69. 2
Baton Rouge	55, 900	8, 920	71. 5
Alexandria	17, 800	3, 980	51. 0
Unassigned	330	70	51. 5
PSA total	141, 300	24, 250	66. 5
*The higher load data requested by Gulf States Utilities Company requires the following addition to load center data in PSA 35 for 1990 only:			
GSU added	56, 059	9, 629	
PSA total	197, 359	33, 879	66. 5
PSA 37:			
Dallas	48, 570	11, 670	47. 5
Fort Worth	16, 800	4, 200	45. 7
Denton	3, 620	910	45. 4
Paris	8, 990	2, 120	48. 5
Sherman	4, 790	1, 070	51. 0
Stephenville	3, 740	950	45. 0
Tyler	4, 770	1, 020	53. 5
Lufkin	9, 350	1, 740	61. 5
Palestine	7, 180	1, 710	48. 0
Waco	6, 800	1, 370	56. 5
Temple	4, 010	900	51. 0
Taylor	6, 220	1, 190	59. 9
Wichita Falls	5, 480	1, 120	56. 0
Abilene	5, 330	1, 020	59. 5
San Angelo	2, 870	600	55. 0
Odessa	21, 200	3, 320	73. 0
Big Spring	7, 800	1, 160	77. 0
Unassigned	480	130	42. 0
PSA total	168, 000	36, 200	53. 0
PSA 38:			
Houston	150, 000	26, 880	63. 7
Austin	18, 900	4, 100	52. 6
San Antonio	16, 400	3, 910	48. 0
Victoria	14, 900	2, 720	62. 5
Corpus Christi	12, 700	2, 420	60. 0
Harlingen	2, 180	480	51. 5
Laredo	3, 700	710	59. 2
Unassigned	1, 120	280	45. 5
PSA total	219, 900	41, 500	60. 5
PSA 17–F (Less Iowa):			
Kansas City	34, 080	7, 340	53. 0

NOTE. Many of the locations are necessarily generalized. Many Load Centers include loads of the surrounding area.

TABLE 9

Industrial Generation for South Central Region (SCRAC)

[Million kwh]

PSA and region	Industrial generation	Industrial purchases	Industrial use	Utility E.F.L. plus industrial generation	Industrial generation	Industrial purchases	Industrial use	Utility E.F.L. plus industrial generation
	1965				1970			
17–F [1]	186	2, 362	2, 548	6, 665	[2] 201	3, 350	3, 551	9, 581
25	8, 591	7, 755	16, 346	29, 640	10, 300	13, 000	23, 300	44, 640
29	73	1, 547	1, 620	5, 308	86	2, 344	2, 430	7, 796
33	546	4, 994	5, 540	16, 379	650	9, 392	10, 042	27, 190
34	315	2, 599	2, 914	7, 600	400	4, 243	4, 643	11, 600
35	4, 472	7, 382	11, 854	17, 757	5, 100	12, 467	17, 567	29, 100
37	3, 554	7, 031	10,585	26, 187	4, 300	11, 400	15, 700	39, 900
38	13, 044	11, 459	24, 503	39, 886	14, 800	20, 268	35, 068	58, 400
South Central region	30, 781	45, 129	75, 910	149, 422	35, 837	76, 464	112, 301	228, 207
	1975				1980			
17–F [1]	[2] 216	4, 750	4, 966	13, 076	[2] 233	6, 600	6, 833	17, 813
25	11, 600	21, 350	32, 950	64, 730	12, 900	33, 000	45, 900	91, 340
29	92	3, 507	3, 599	10, 642	98	5, 358	5, 456	14, 448
33	735	15, 298	16, 033	41, 575	820	22, 855	23, 675	60, 900
34	440	6, 390	6, 830	16, 640	480	9, 570	10, 050	23, 480
35	5, 700	21, 546	27, 246	46, 300	6, 350	34, 971	41, 321	70, 850
37	4, 700	19, 325	24, 025	60, 000	5, 100	29, 366	34, 466	87, 100
38	16, 300	32, 163	48, 463	84, 000	17, 900	49, 698	67, 598	120, 580
South Central Region	39, 783	124, 329	164, 112	336, 963	43, 881	191, 418	235, 299	486, 511
	1985				1990			
17–F [1]	[2] 251	9, 300	9, 551	24, 761	[2] 270	13, 000	13, 270	34, 350
25	14, 200	47, 000	61, 200	124, 810	15, 500	64, 000	79, 500	167, 800
29	104	8, 172	8, 276	19, 384	110	12, 215	12, 325	25, 740
33	920	33, 099	34, 019	85, 550	1, 000	48, 736	49, 736	117, 270
34	520	14, 400	14, 920	32, 320	560	21, 030	21, 590	43, 460
35	7, 000	53, 825	60, 825	104, 700	7, 600	79, 650	87, 250	148, 900
37	5, 500	45, 265	50, 765	124, 100	5, 900	68, 912	74, 812	173, 900
38	19, 400	75, 038	94, 438	171, 825	21, 000	111, 420	132, 420	240, 900
South Central Region	47, 895	286, 099	333, 994	687, 450	51, 940	418, 963	470, 903	952, 320

[1] Does not include portion of Iowa.

[2] Estimated by FWRO.

TABLE 10

Non-Farm Residential Appliances, South Central Region, 1965–1990

Appliances	Annual kwh per appliance	Estimated saturation (percent)	Average annual kwh per customer	Annual kwh per appliance	Estimated saturation (percent)	Average annual kwh per customer	Annual kwh per appliance	Estimated saturation (percent)	Average annual kwh per customer
	Year 1965			Year 1966			Year 1970		
Refrigerator	600	96	576	610	96	585	650	97	630
Range	1, 200	30	360	1, 200	31	372	1, 200	32	384
Water Heater	3, 600	8	288	3, 700	9	333	4, 000	12	480
Freezer	1, 100	29	319	1, 100	29	319	1, 100	32	352
Central Airconditioning	4, 500	10	450	4, 500	10	450	4, 700	15	705
Room Airconditioning	2, 000	36	720	2, 000	37	740	2, 300	40	920
Washing Machine	65	76	49	66	76	50	70	80	56
Ironer	140	5	7	140	5	7	144	6	9
Dryer (Clothes)	950	20	190	950	21	200	975	25	244
Vacuum Cleaner	30	72	22	30	72	22	35	75	26
Dishwasher	300	12	36	300	13	39	310	15	47
Food Waste Disposer	30	13	4	30	13	4	32	15	5
Radio	90	100	90	90	100	90	90	100	90
Television	320	88	282	320	88	282	330	90	300
Heat Pump	12, 000	2	240	12, 000	3	360	13, 000	5	650
Complete Heating	10, 000	1	100	10, 000	2	200	11, 000	6	660
Supplemental Heating	550	19	105	550	20	110	575	21	121
Lighting			690			710			750
Miscellaneous			425			437			571
Total			4, 953			5, 310			7, 000
	Year 1975			Year 1980			Year 1985		
Refrigerator	700	98	686	750	99	742	800	99	792
Range	1, 200	35	420	1, 200	40	480	1, 200	45	540
Water Heater	4, 400	17	748	4, 800	22	1, 056	5, 200	30	1, 560
Freezer	1, 100	35	385	1, 100	38	418	1, 200	41	492
Central Airconditioning	4, 900	23	1, 127	5, 100	33	1, 683	5, 300	40	2, 120
Room Airconditioning	2, 500	41	1, 025	2, 800	42	1, 176	3, 000	38	1, 140
Washing Machine	75	82	62	80	84	67	90	86	77
Ironer	148	7	10	152	8	12	155	9	14
Dryer (Clothes)	1, 000	30	300	1, 025	35	359	1, 050	40	420
Vacuum Cleaner	40	78	31	45	80	36	50	82	41
Dishwasher	320	20	64	330	25	83	340	30	102
Food Waste Disposer	35	18	6	38	22	8	42	25	11
Radio	90	100	90	90	100	90	90	100	90
Television	340	92	313	350	94	329	360	96	346
Heat Pump	14, 000	6	840	15, 000	6	900	16, 000	6	960
Complete Heating	12, 000	10	1, 200	13, 000	17	2, 210	14, 000	25	3, 500
Supplemental Heating	600	26	156	625	29	181	650	34	221
Lighting			900			1, 000			1, 050
Miscellaneous			987			1, 340			1, 824
Total			9, 350			12, 170			15, 300

TABLE 10—Continued

Appliances	Annual kwh per appliance	Estimated saturation (percent)	Average annual kwh per customer
	Year 1990		
Refrigerator	850	100	850
Range	1, 200	50	600
Water Heater	5, 600	39	2, 184
Freezer	1, 200	45	540
Central Airconditioning	5, 500	50	2, 750
Room Airconditioning	3, 200	35	1, 120
Washing Machine	110	88	97
Ironer	158	10	16
Dryer (Clothes)	1, 075	45	484
Vacuum Cleaner	55	84	46
Dishwasher	350	35	123
Food Waste Disposer	45	28	13
Radio	90	100	90
Television	370	98	363
Heat Pump	17, 000	5	850
Complete Heating	15, 000	33	4, 950
Supplemental Heating	675	39	263
Lighting			1, 100
Miscellaneous			2, 071
Total			18, 510

TABLE 11

Kilowatt-Hours per Employee and per Capita for South Central Region, 1965–1990

Year	Industrial energy use (gwh)	Industrial employment (thousands)	Kwh per employee	Utility E.F.L. plus ind. gen. (gwh)	Population (thousands)	Kwh per capita
1965 [1]	75, 910	1, 627	46, 656	149, 422	22, 940	6, 514
1970 [2]	112, 301	1, 734	64, 764	228, 207	24, 425	9, 343
1975 [2]	164, 112	1, 861	88, 185	336, 963	26, 217	12, 853
1980 [2]	235, 299	2, 012	116, 948	486, 511	28, 342	17, 166
1985 [2]	333, 994	2, 178	153, 349	687, 450	30, 680	22, 407
1990 [2]	470, 903	2, 347	200, 640	952, 320	33, 060	28, 806

[1] Actual.
[2] Estimated.

TABLE 12

Economic Data by Regions—South Central Region

Cash Receipts from Farm Marketing, 1966 [1] (millions of dollars):	
Livestock & Livestock Products	$4, 115. 0
Crops	$3, 236. 0
Total	$7, 351. 0
Number of Farms, End of 1959 [2]	727, 000
Number Farms, July 1966 [3]	583, 427
Value of Mineral Products, 1965 [4] (millions of dollars)	$8, 803. 6
Value Added by Manufacture, 1964 [5] (millions of dollars)	$15, 857. 0

TABLE 12—Continued

Population, July 1, 1966, (thousands) : [6]	
Farm	2, 052
Nonfarm	19, 800
Total	23, 238

[1] Data from Bulletin FIS–207, "Farm Income Situation," U.S. Department of Agriculture.

[2] Data abstracted and adjusted from Section 23 of "Statistical Abstract of the United States," 1967, U.S. Department of Commerce.

[3] Data estimated from 1967 load forecast.

[4] "1965 Minerals Yearbook," Vol. III, Bureau of Mines, U.S. Department of Interior.

[5] Interpolated from Sec. 29 of "Statistical Abstract of the United States," 1967, U.S. Department of Commerce.

[6] Estimated from Bureau of Census data of April 1960.

TABLE 13

Estimated Coal Requirements of Generating Facilities—South Central Region

Year	Estimated generation using coal (millions kwh)	Estimated btu requirements (trillion btu)	Estimated coal required in tons (thousands ton equiv.)	Estimated average heat rate net	Estimated coal required previous 5 year period ending (thousands ton equiv.)
1966	5, 280	59	2, 460	11, 500	....
1970	7, 370	77	3, 200	10, 700	14, 155
1975	24, 350	243	10, 200	10, 100	26, 000
1980	42, 900	424	17, 600	9, 900	76, 200
1985	70, 000	687	28, 600	9, 850	121, 000
1990	94, 100	925	38, 500	9, 800	173, 300
Total (in period reviewed)					410, 655

BTU estimated 12,000 per pound for coal, 7,000 per pound for lignite.
Ton equals 2,000 pounds.

NOTE. The BTU requirement computation was based on net average system heat rate and included all types of fuel. However, these figures appear realistic when compared with actual and projected heat rates for coal burning units.

TABLE 14

South Central Region—Sources of Supply From Outside the South Central Region and Obligations of the South Central Region to Other Regions

Sources of supply	Recipient	1970	1980	1990
Union Electric	Missouri Utilities	106	236	522
TVA	SCEC [1]	1, 500	1, 500	1, 500
SCEC	TVA [2]	1, 500	1, 500	1, 500

[1] Summer only.

[2] Winter only.

TABLE 15

South Central Region—Maximum Plant Sizes, Maximum Unit Sizes and Their Percentages of Peak Load

PSA	Peak load	Maximum plant size	Percent of load	Maximum unit size	Percent of load
			1970		
17F	2, 100	857	41	494	24
25	7, 260	1, 240	17	750	10
29	1, 760	346	20	172	10
33	6, 120	888	15	450	7
34	2, 460	518	21	370	15
35	4, 240	952	22	530	13
37	7, 970	956	12	550	7
38	8, 510	1, 534	18	750	9
Average	5, 052	911	18	508	10
			1980		
17F	3, 860	1, 600	41	1, 000	26
25	16, 400	1, 850	11	925	6
29	3, 250	1, 430	44	800	25
33	13, 800	1, 500	11	1, 000	7
34	4, 950	2, 000	40	1, 000	20
35	11, 240	2, 298	20	1, 060	9
37	18, 000	2, 250	13	1, 000	6
38	19, 700	2, 750	14	1, 000	5
Average	11, 400	1, 960	17	973	9
			1990		
17F	7, 340	2, 500	34	1, 500	20
25	31, 500	4, 150	13	1, 700	5
29	5, 760	2, 800	49	1, 000	17
33	26, 600	5, 135	19	1, 350	5
34	9, 070	4, 000	44	1, 250	14
35	33, 879	6, 470	19	1, 645	5
37	36, 200	3, 500	10	1, 500	4
38	41, 500	4, 000	10	1, 500	4
Average	23, 981	4, 069	17	1, 431	6

Summary of Averages

Year	Peak load	Maximum plant size	Percent of load	Maximum unit size	Percent of load
1970	5, 052	911	18	508	10
1980	11, 400	1, 960	17	978	9
1990	23, 981	4, 069	17	1, 431	6

TABLE 16

South Central Region—Hydro Resources

Project	State	Stream	Type	Capacity, MW: Existing and under-construction	Capacity, MW: Potential for 1980	Capacity, MW: Potential for 1990
PSA 25:						
Norfork	Arkansas	White	HY	70	85	
Bull Shoals	Arkansas	White	HY	340		
Carpenter	Arkansas	Ouachita	HY	56		
Blakely	Arkansas	Ouachita	HY	75		
Remmel	Arkansas	Ouachita	HY	10		
Greers Ferry	Arkansas	Little Red	HY	93		
Dardanelle	Arkansas	Arkansas	HY	124		
DeGray	Arkansas	Caddo	HY		40	
DeGray	Arkansas	Caddo	PS		28	
Wolf Bayou	Arkansas	White	HY		180	
Optimus	Arkansas	White	PS		500	
Petit Jean	Arkansas	Arkansas	PS		561	
Bell Foley	Arkansas	Strawberry	HY			24
Area total				768	1, 394	24
PSA 33:						
Pensacola	Oklahoma	Grand	HY	86		
Narrows	Arkansas	Little Mo	HY	21		
Ft. Gibson	Oklahoma	Grand	HY	45		
Markham Ferry	Oklahoma	Grand	HY	108		
Tenkiller Ferry	Oklahoma	Illinois	HY	34		
Eufaula	Oklahoma	Canadian	HY	90		
Keystone	Oklahoma	Arkansas	HY	72		
Broken Bow	Oklahoma	Mt. Fork	HY	86		
R. S. Kerr	Oklahoma	Arkansas	HY	55	55	
Webber Falls	Oklahoma	Arkansas	HY		66	
Kaw	Oklahoma	Arkansas	HY		25	
Salina	Oklahoma	Salina	PS	130	390	
Tuskahoma	Oklahoma	Kiamichi	PS		1, 000	
Grandview	Arkansas	Kings	HY			18
Buck Creek	Oklahoma	Buck Creek	HY			12
Hugo Dam	Oklahoma	Kiamichi	HY			50
Pine Creek	Oklahoma	Little	HY			86
Lukfata	Oklahoma	Glover Creek	HY			35
Tuskahoma	Oklahoma	Kiamichi	HY			19
Hartley	Arkansas	Cossatot	HY			14
Sherwood	Oklahoma	Mountain Fork	HY			103
Gainesville	Oklahoma	Red	HY			50
Dougherty	Oklahoma	Washita	HY			25
Durwood	Oklahoma	Washita	HY			20
Denison	Oklahoma	Red	HY	35		52
Upper Antlers	Oklahoma	Kiamichi	HY			90
Sherwood	Oklahoma	Mountain Fork	PS			500
Boktukola	Oklahoma	Boktukola	PS			1, 000
Ozark	Arkansas	Arkansas	HY		100	
Area total				762	1, 636	2, 074

TABLE 16—Continued

Project	State	Stream	Type	Capacity, MW: Existing and under-construction	Potential for 1980	Potential for 1990
PSA 34:						
Beaver	Arkansas	White	HY	112		
Ozark Beach	Arkansas	White	HY	16		
Table Rock	Missouri	White	HY	200		
Stockton	Missouri	Sac	HY	44		
Clarence Cannon	Missouri	Salt	HY		27	
Clarence Cannon	Missouri	Salt	PS		27	
Kaysinger Bluff	Missouri	Osage	PS		160	
Galena	Missouri	James	HY			43
Mulladay	Missouri	White	PS			485
Area total				372	214	528
PSA 35:						
Toledo Bend	Texas	Sabine	HY	80		
Sam Rayburn	Texas	Angelina	HY	49		
State Line	Texas	Sabine	HY			134
Carthage	Texas	Sabine	HY			16
Bon Wier	Texas	Sabine	HY			20
Area total				129	0	170
PSA 37:						
Denison	Texas	Red	HY	35		52
Whitney	Texas	Brazos	HY	28		
Possum Kingdom	Texas	Brazos	HY	22		11
Gainesville	Texas	Red	HY			50
Area total				85	0	113
PSA 38:						
Buchanan	Texas	Colorado	HY	34		
Inks	Texas	Colorado	HY	12		
Granite Shoals	Texas	Colorado	HY	45		
Marble Falls	Texas	Colorado	HY	30		
Mansfield	Texas	Colorado	HY	68		
Austin	Texas	Colorado	HY	14		
Falcon	Texas	Colorado	HY	32		
Choke Canyon	Texas	Nueces	HY			12
Area total				235	0	12
Total for region				2, 351	3, 244	2, 921
Accumulated total end of 1990						8, 516

TABLE 17

South Central Region—Retirements

	1968 thru 1970 [1] #Units	1968 thru 1970 [1] MW	1971 thru 1980 [1] #Units	1971 thru 1980 [1] MW	1981 thru 1990 [2] #Units	1981 thru 1990 [2] MW
PSA 17–F:						
Steam:						
100 MW and smaller	10	173	8	129	19	661
101 MW to 300 MW					4	600
Subtotal Steam	10	173	8	129	23	1261
Internal Combustion		1		2		10
Total MW		174		131		1, 271
PSA 25:						
Steam:						
100 MW and smaller	16	193	7	155	40	1, 102
101 MW to 300 MW					10	1, 398
Subtotal Steam	16	193	7	155	50	2, 500
Internal Combustion		9		19		88
Total MW		202		174		2, 588
PSA 29:						
Steam:						
100 MW and smaller	10	58	9	45	29	534
101 MW to 300 MW					1	130
Subtotal Steam	10	58	9	45	30	664
Internal Combustion		8		16		119
Total MW		66		61		783
PSA 33:						
Steam:						
100 MW and smaller	21	264	10	79	29	914
101 MW to 300 MW					10	1, 560
Subtotal Steam	21	264	10	79	39	2, 474
Internal Combustion		8		13		52
Total MW		272		92		2, 526
PSA 34:						
Steam:						
100 MW and smaller	20	130	7	72	22	583
101 MW to 300 MW					2	245
Subtotal Steam	20	130	7	72	24	828
Internal Combustion		3		10		34
Total MW		133		82		862
PSA 35:						
Steam:						
100 MW and smaller	7	74	5	69	29	793
101 MW to 300 MW					6	768
Subtotal Steam	7	74	5	69	35	1, 561
Internal Combustion		5		17		40
Total MW		79		86		1, 601

See footnotes at end of table.

TABLE 17—Continued

	1968 thru 1970 [1] #Units	MW	1971 thru 1980 [1] #Units	MW	1981 thru 1990 [2] #Units	MW
PSA 37:						
Steam:						
100 MW and smaller	16	273	5	100	41	1, 320
101 MW to 300 MW					14	2, 145
Subtotal Steam	16	273	5	100	55	3, 465
Internal Combustion		16		16		50
Total MW		289		116		3, 515
PSA 38:						
Steam:						
100 MW and smaller	13	252	9	158	30	1, 339
101 MW to 300 MW					18	2, 632
Subtotal Steam	13	252	9	158	48	3, 971
Internal Combustion		1		1		5
Total MW		253		159		3, 976
Total South Central Region:						
Steam:						
100 MW and smaller	113	1, 417	60	807	239	7, 246
101 MW to 300 MW					65	9, 478
Subtotal Steam	113	1, 417	60	807	304	16, 724
Internal Combustion		51		94		398
Total MW		1, 468		901		17, 122

[1] Estimated Life 35 years (1964 NPS II Advisory Committee Report #4).
[2] Estimated Life 30 years (1964 NPS II Advisory Committee Report #4).

TABLE 18

South Central Region—Capacity and Load Balance

PSA	17–F	25	29	33	34	35	37	38
1970								
Capacity [1]	2, 423	8, 244	1, 793	5, 996	2, 844	4, 800	9, 356	10, 448
Peak Load	2, 100	7, 260	1, 760	6, 120	2, 460	4, 240	7, 970	8, 510
1980								
Additions [1]	1, 800	11, 591	2, 050	9, 567	3, 852	8, 860	11, 614	13, 398
Retirements	131	174	61	92	82	86	116	159
Capacity	4, 092	19, 661	3, 782	15, 471	6, 614	13, 574	20, 854	23, 687
Peak Load	3, 860	16, 400	3, 250	13, 800	4, 950	11, 240	18, 000	19, 700
1990								
Additions [1]	5, 115	16, 124	3, 500	19, 700	5, 011	26, 077	24, 449	28, 316
Retirements	1, 271	2, 588	783	2, 526	862	1, 601	3, 515	3, 976
Capacity	7, 936	33, 197	6, 499	32, 645	10, 763	38, 050	41, 788	48, 027
Peak Load	7, 340	31, 500	5, 760	26, 600	9, 070	33, 879	36, 200	41, 500

Total Region	*1970*	*1980*	*1990*
Additions		62, 732	128, 292
Retirements		901	17, 122
Capacity	45, 904	107, 735	218, 905
Peak Load	40, 301	90, 980	191, 440
Outside Sources	1, 606	1, 736	2, 022
Peak Requirement	38, 695	89, 244	189, 418
MW Reserve	7, 209	18, 491	29, 487
%Reserve	18. 63	20. 72	15. 57

[1] Includes small units and other units not included in Plant List; excludes diversity and firm purchase contracts.

SOUTH CENTRAL REGIONAL ADVISORY COMMITTEE

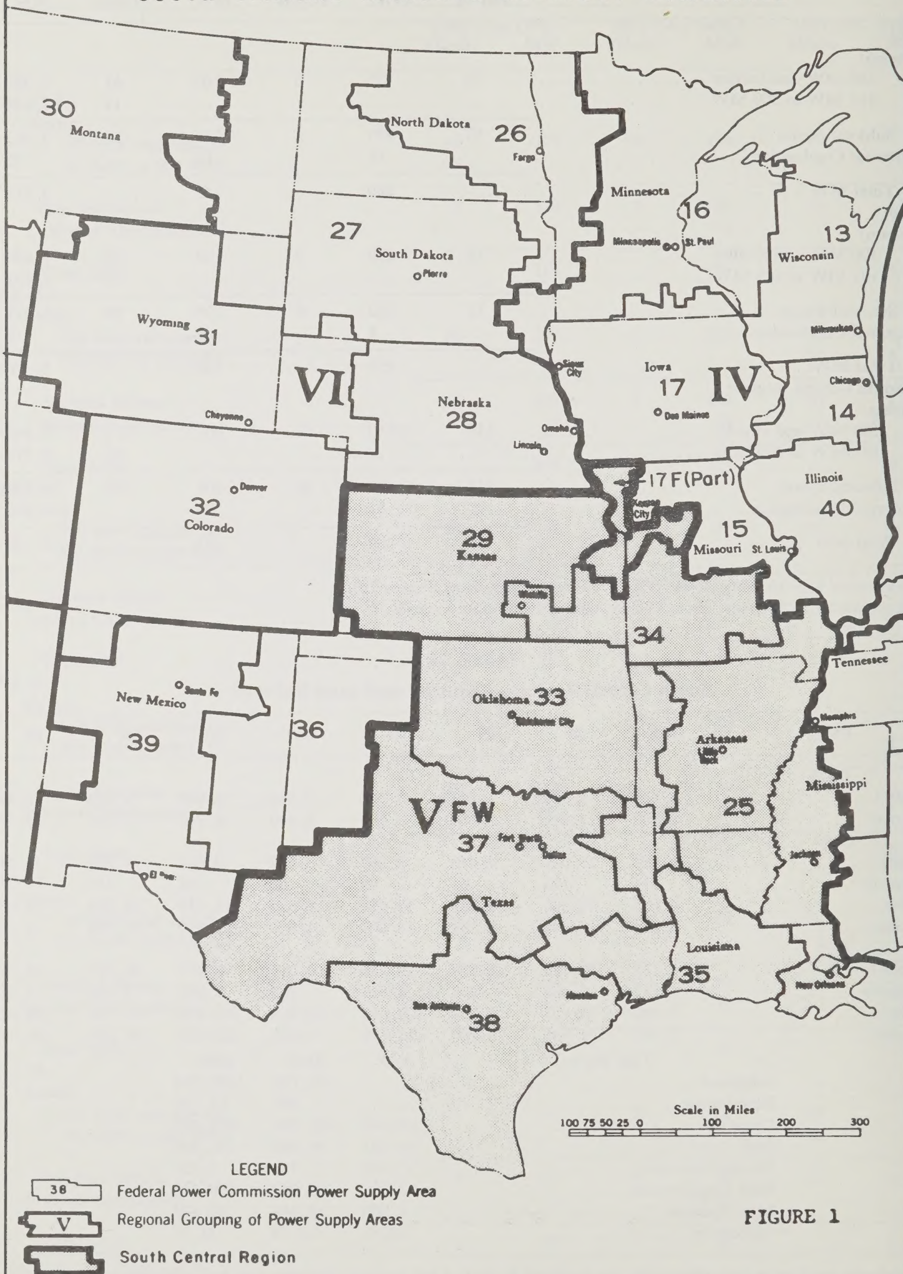
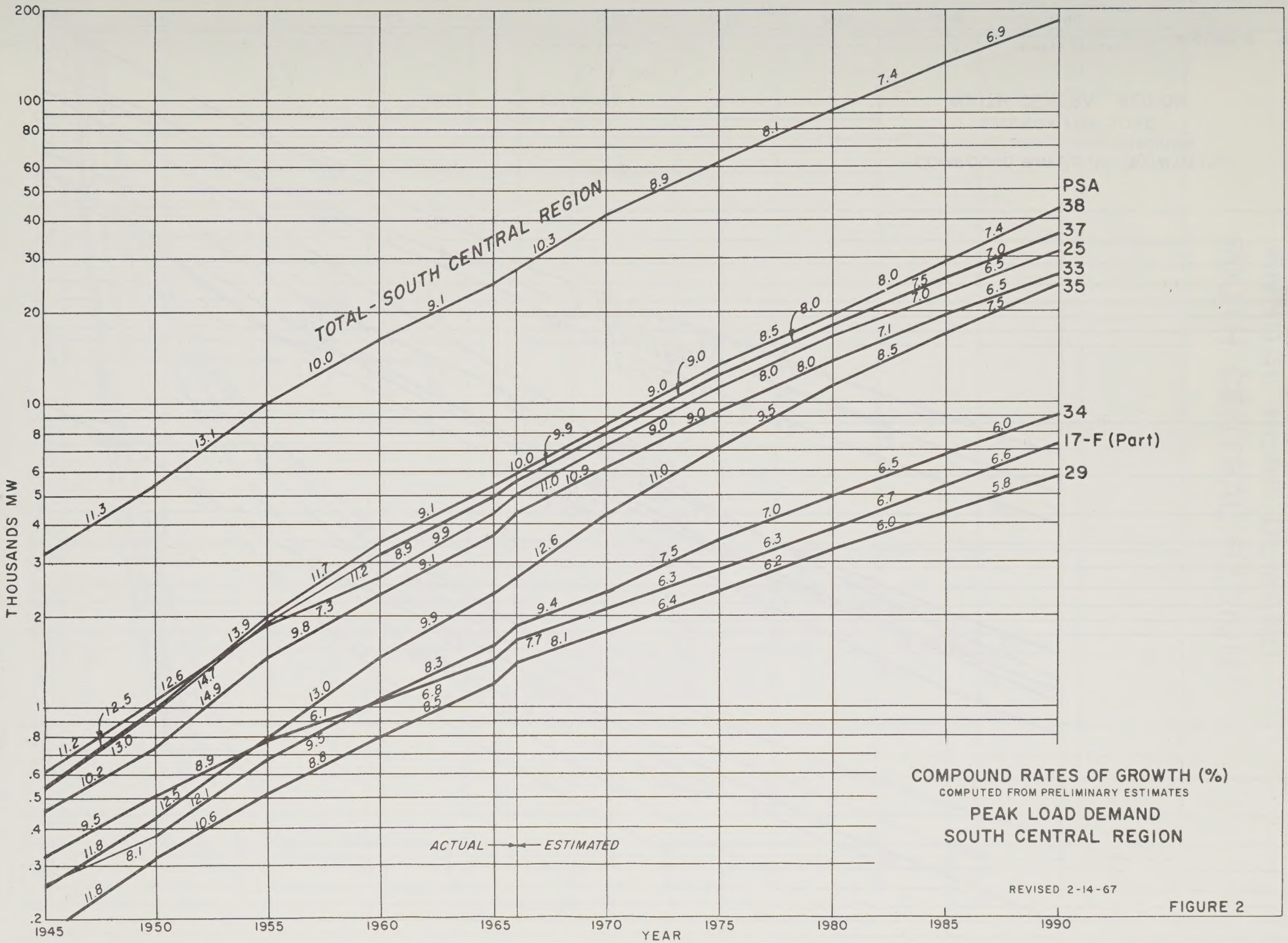


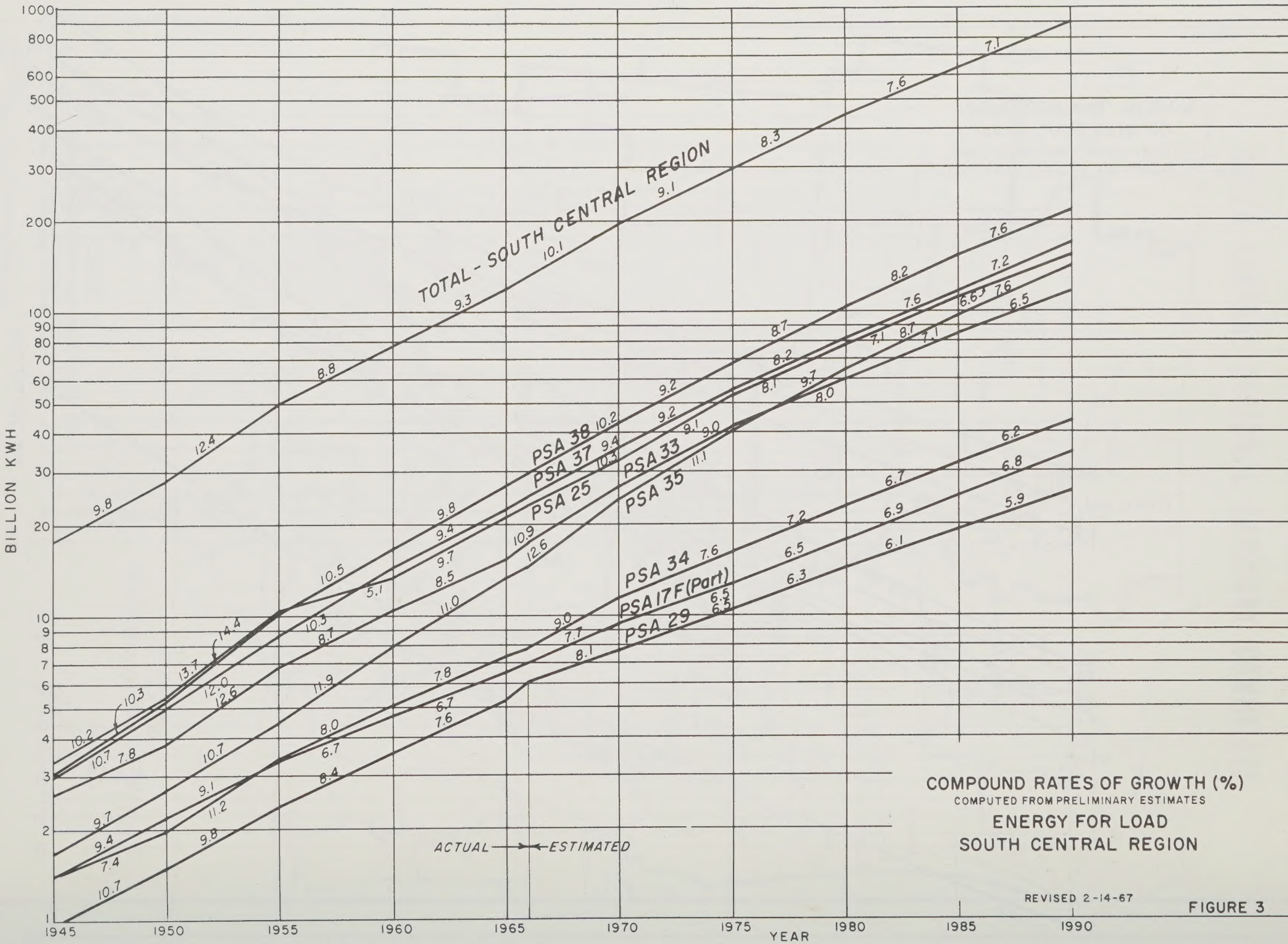
FIGURE 1



COMPOUND RATES OF GROWTH (%)
COMPUTED FROM PRELIMINARY ESTIMATES
PEAK LOAD DEMAND
SOUTH CENTRAL REGION

REVISED 2-14-67

FIGURE 2



COMPOUND RATES OF GROWTH (%)
COMPUTED FROM PRELIMINARY ESTIMATES
ENERGY FOR LOAD
SOUTH CENTRAL REGION

REVISED 2-14-67

FIGURE 3

ANNUAL PEAK DEMAND
SOUTH CENTRAL REGION

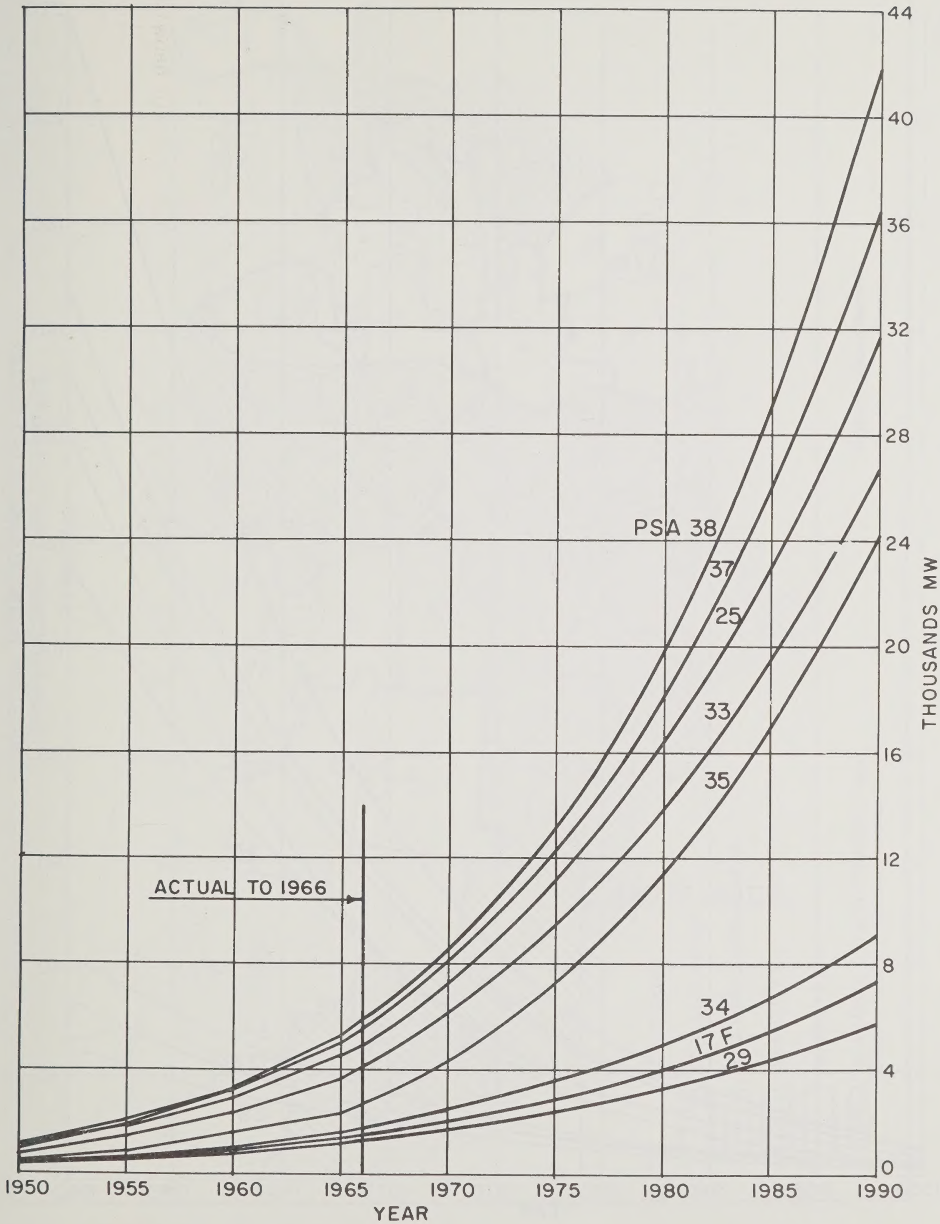


FIGURE 4

MAY, 1968

356-240 O—70——6

ENERGY FOR LOAD
SOUTH CENTRAL REGION

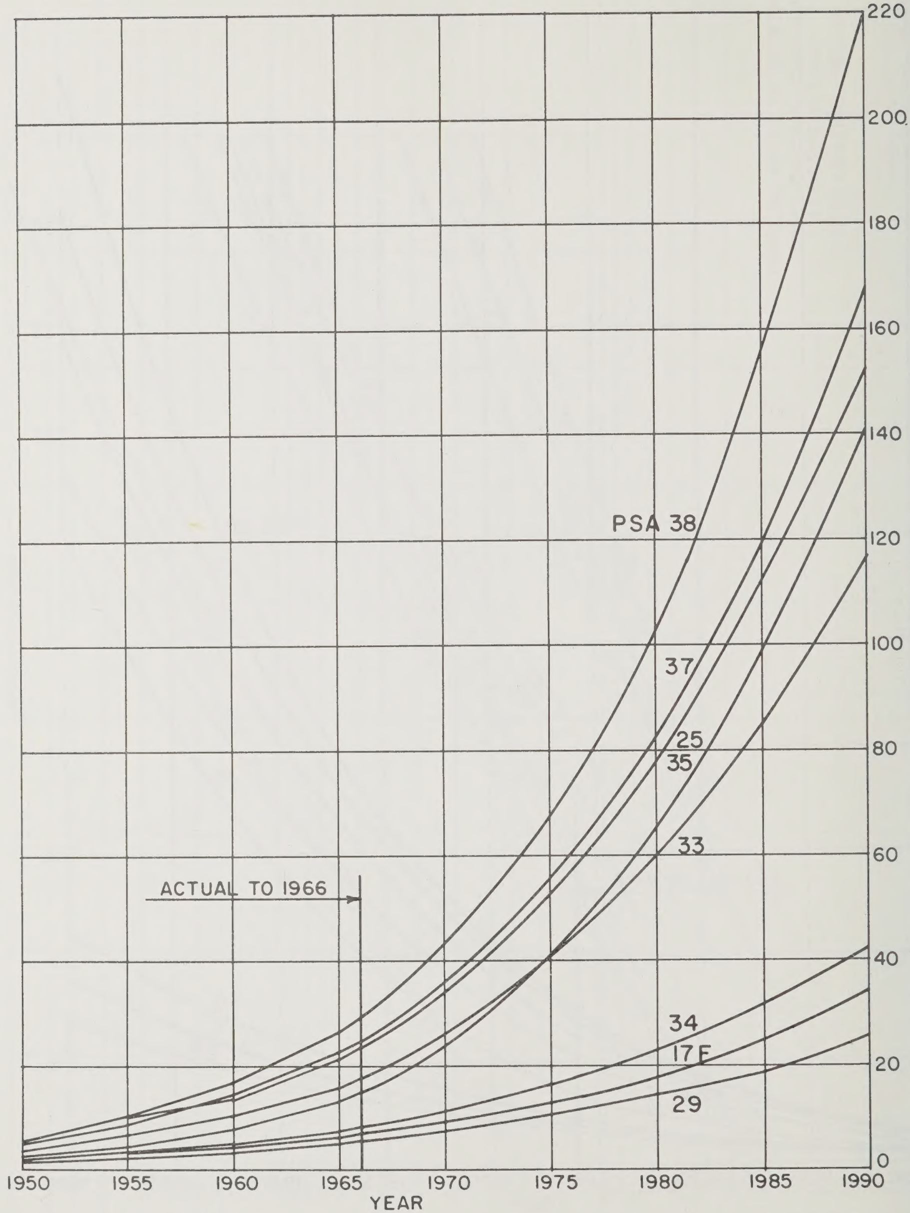


FIGURE 5

MAY, 1968

LOAD STUDY AREAS IN THE UNITED STATES
SHOWING SEASONAL LOAD DIFFERENCES
YEAR 1960

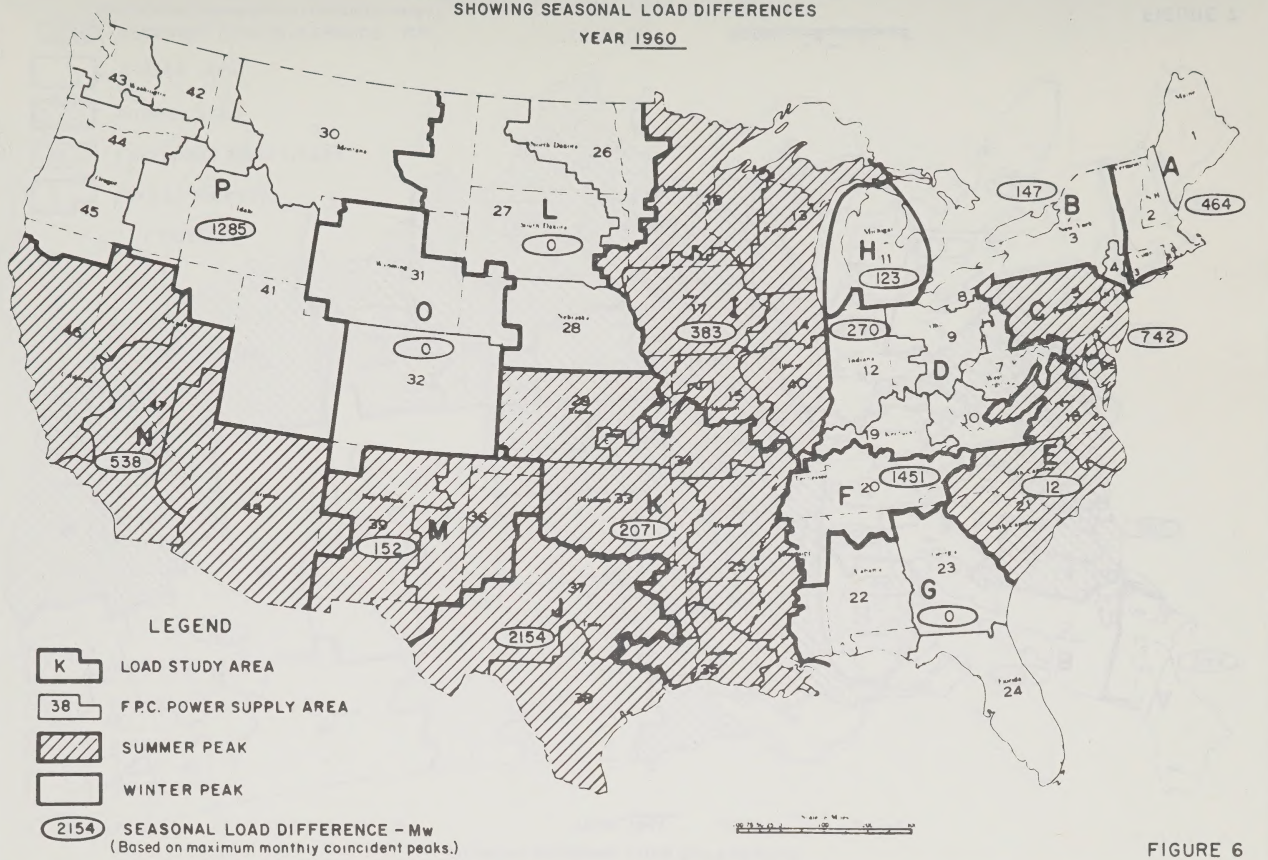
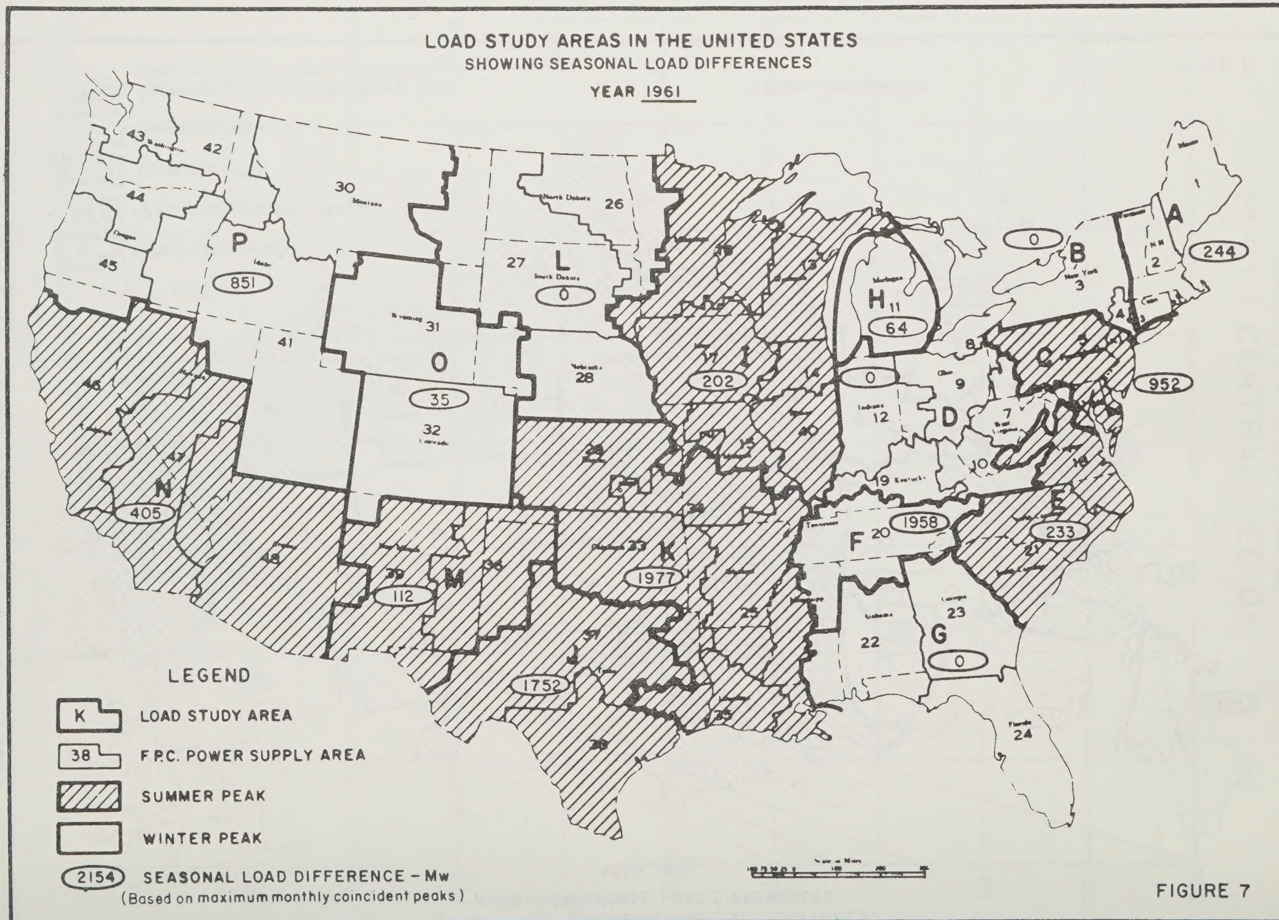


FIGURE 6


LOAD STUDY AREAS IN THE UNITED STATES
SHOWING SEASONAL LOAD DIFFERENCES
YEAR 1961
LEGEND
K LOAD STUDY AREA
38 F.P.C. POWER SUPPLY AREA
SUMMER PEAK
WINTER PEAK
2154 SEASONAL LOAD DIFFERENCE – Mw
(Based on maximum monthly coincident peaks)
A
244
B
0
C
952
D
E
233
F
1958
G
0
H
64
0
K
1977
L
0
M
112
N
405
O
35
P
851
202
1752
FIGURE 7

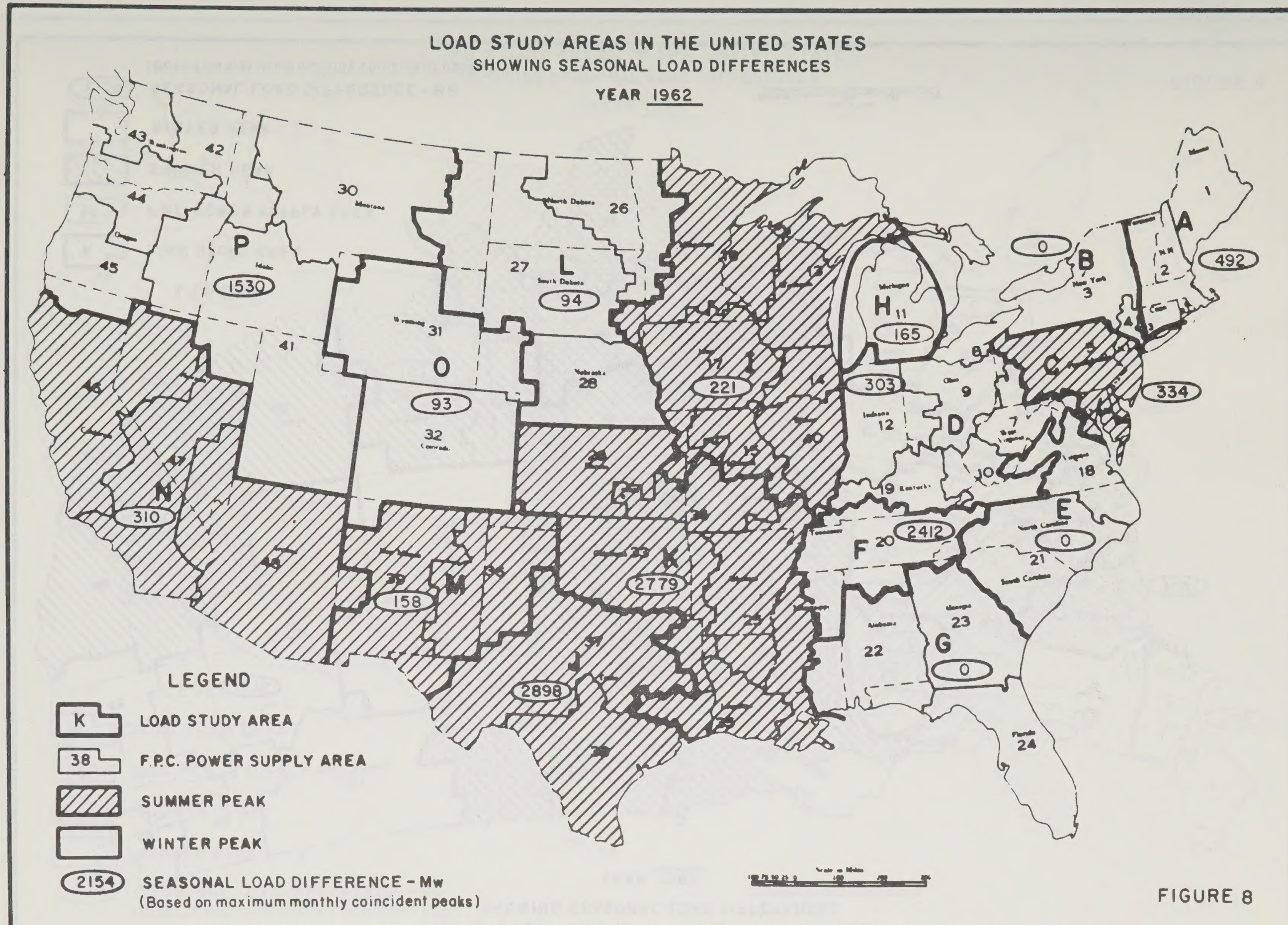
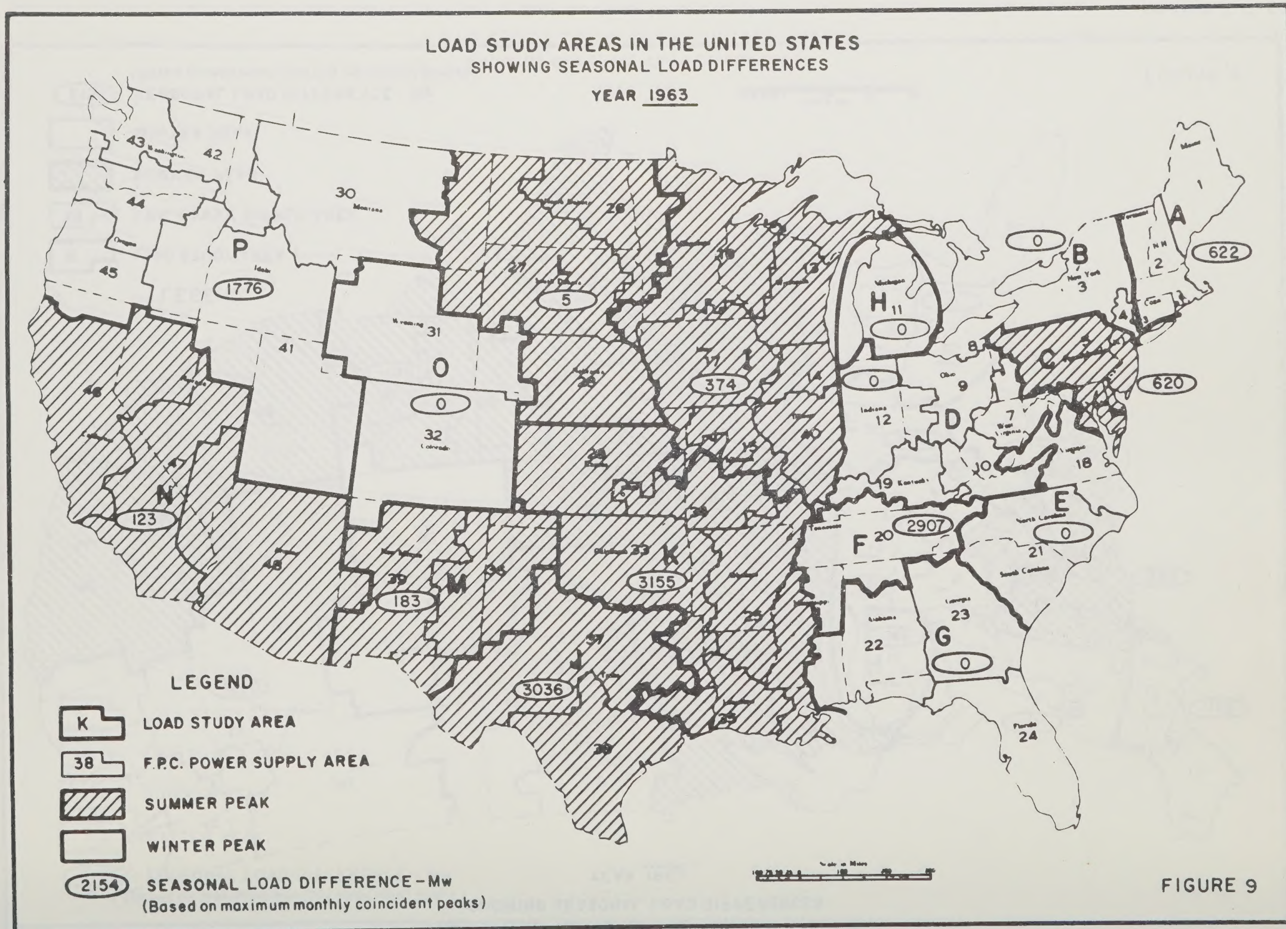


FIGURE 8

REVISED 7-17-68

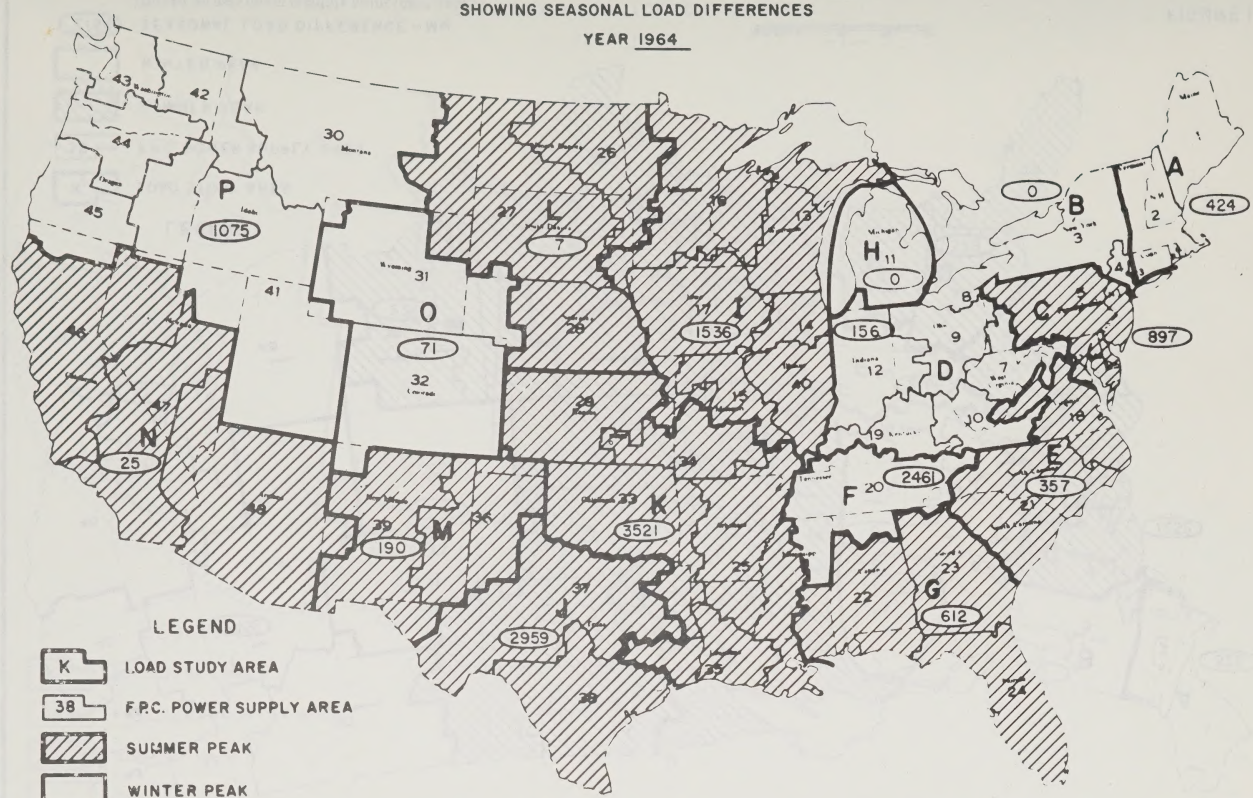


LOAD STUDY AREAS IN THE UNITED STATES
SHOWING SEASONAL LOAD DIFFERENCES
YEAR 1963

FIGURE 9

REVISED 7-17-68

LOAD STUDY AREAS IN THE UNITED STATES
SHOWING SEASONAL LOAD DIFFERENCES
YEAR 1964



LEGEND

K LOAD STUDY AREA

38 F.P.C. POWER SUPPLY AREA

SUMMER PEAK

WINTER PEAK

2154 SEASONAL LOAD DIFFERENCE - Mw
(Based on maximum monthly coincident peaks)

FIGURE 10

LOAD STUDY AREAS IN THE UNITED STATES
SHOWING SEASONAL LOAD DIFFERENCES
YEAR 1965

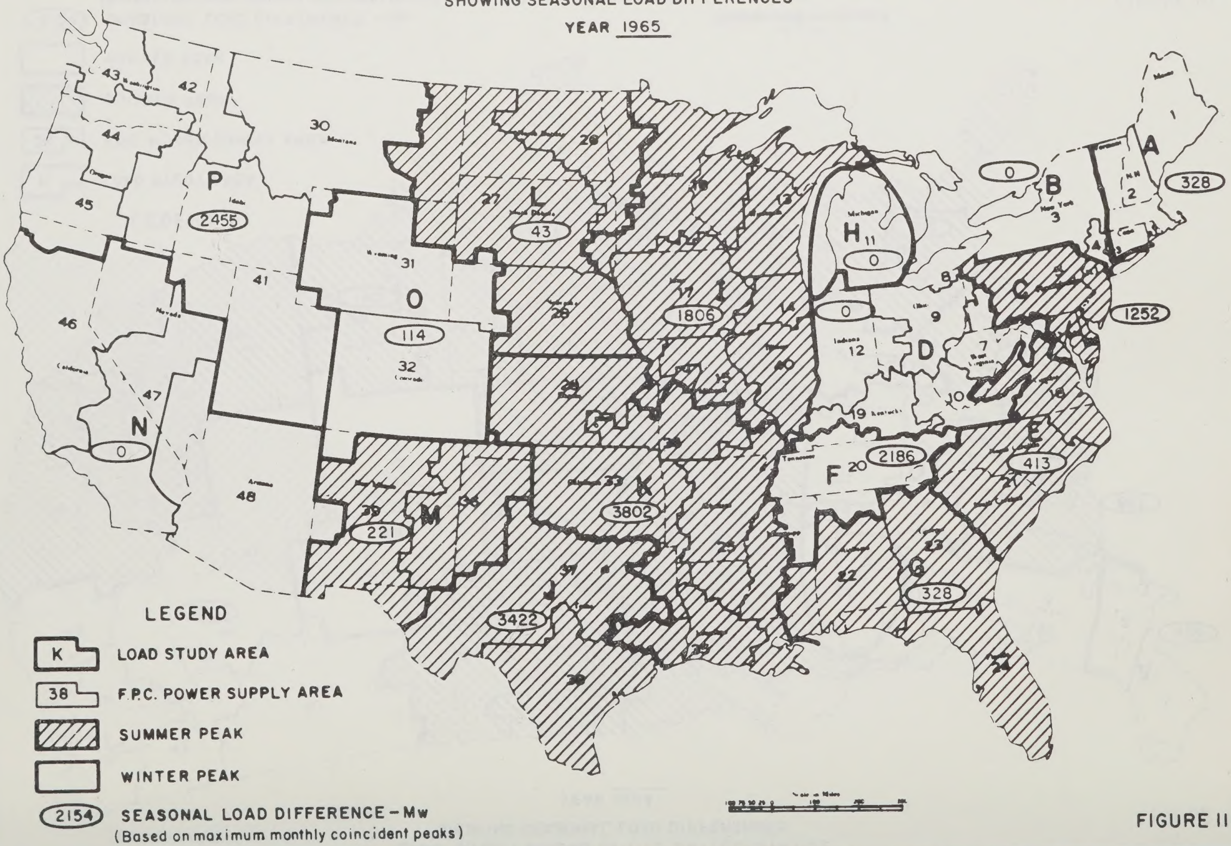


FIGURE II

REVISED 7-17-68

LOAD STUDY AREAS IN THE UNITED STATES
SHOWING SEASONAL LOAD DIFFERENCES
YEAR 1966

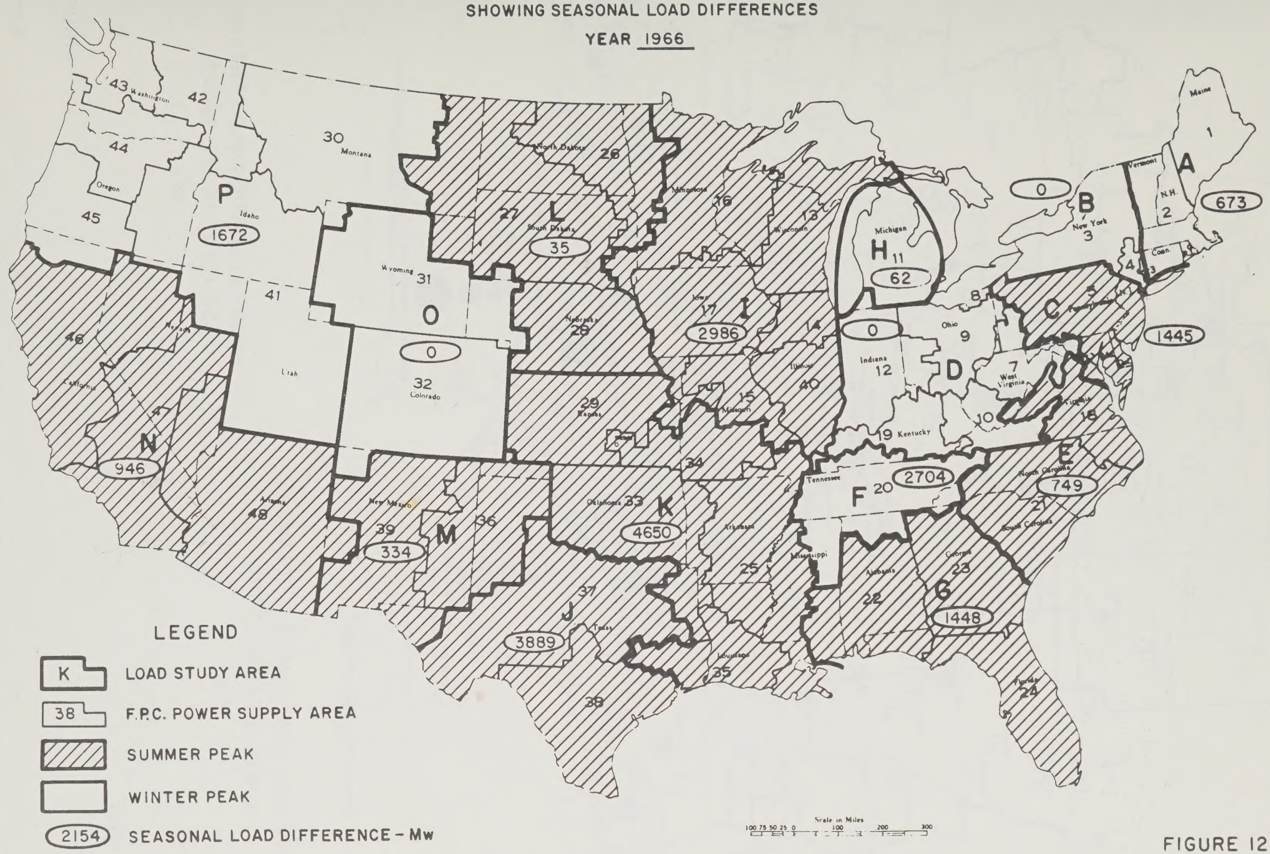
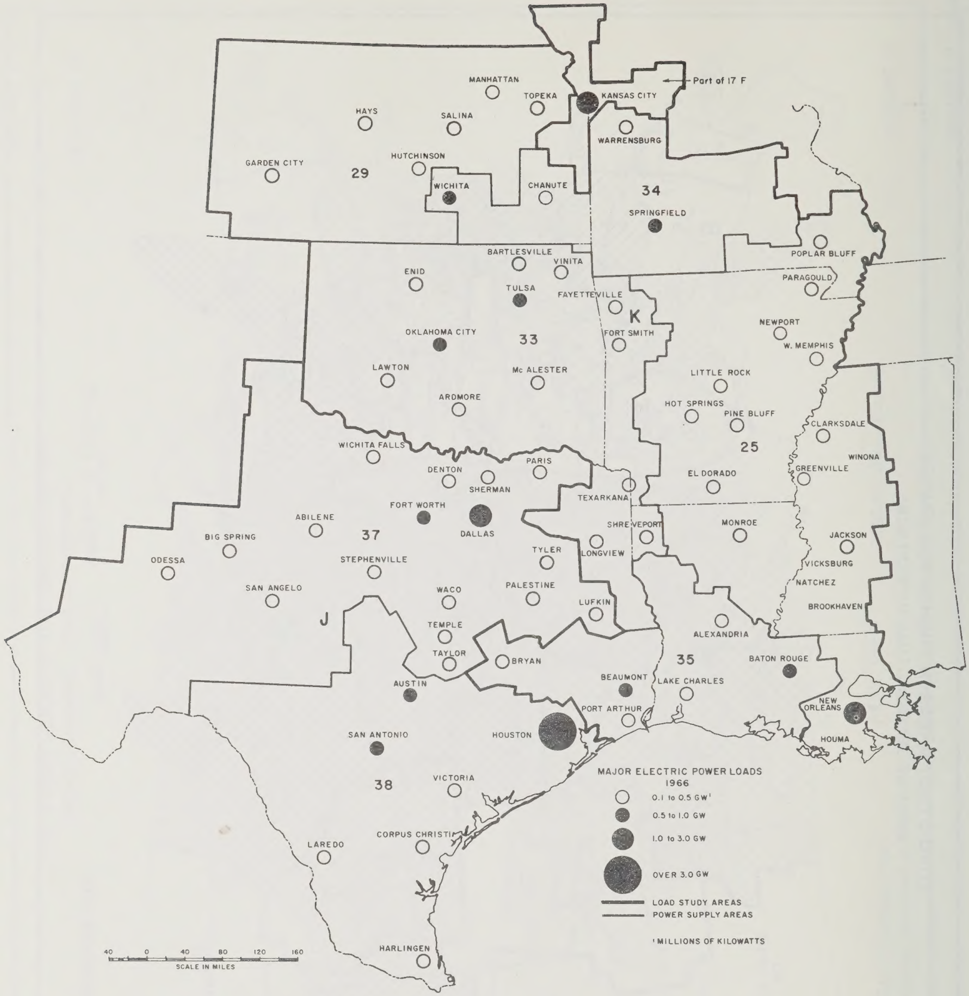


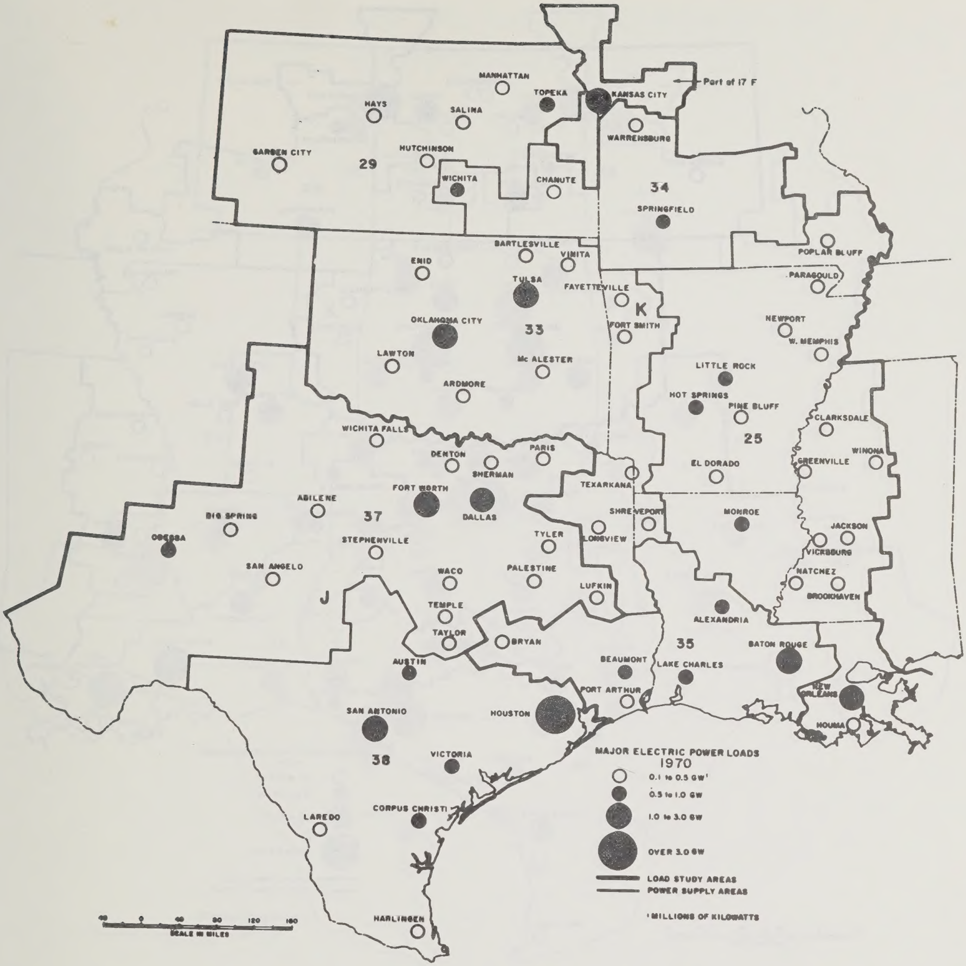
FIGURE 12

REVISED 7-17-68



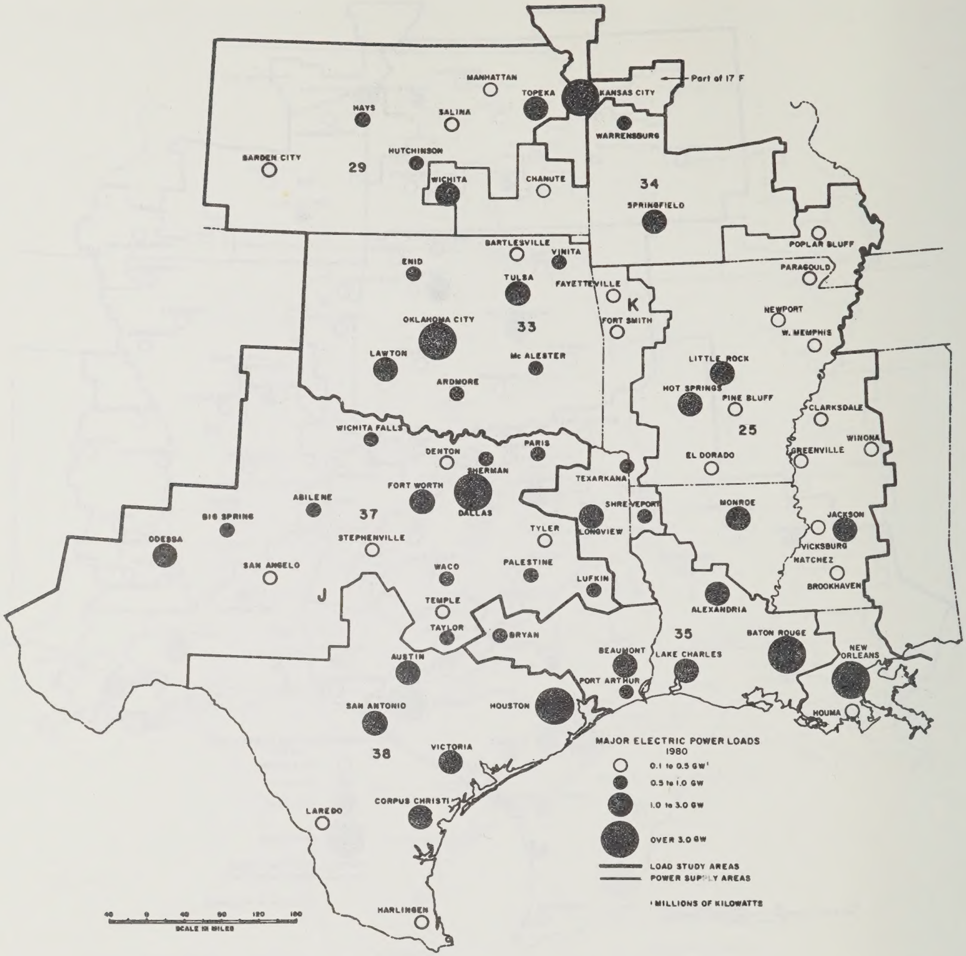
MAJOR ELECTRIC LOAD CENTERS
SOUTH CENTRAL REGION
1966

FIGURE 13



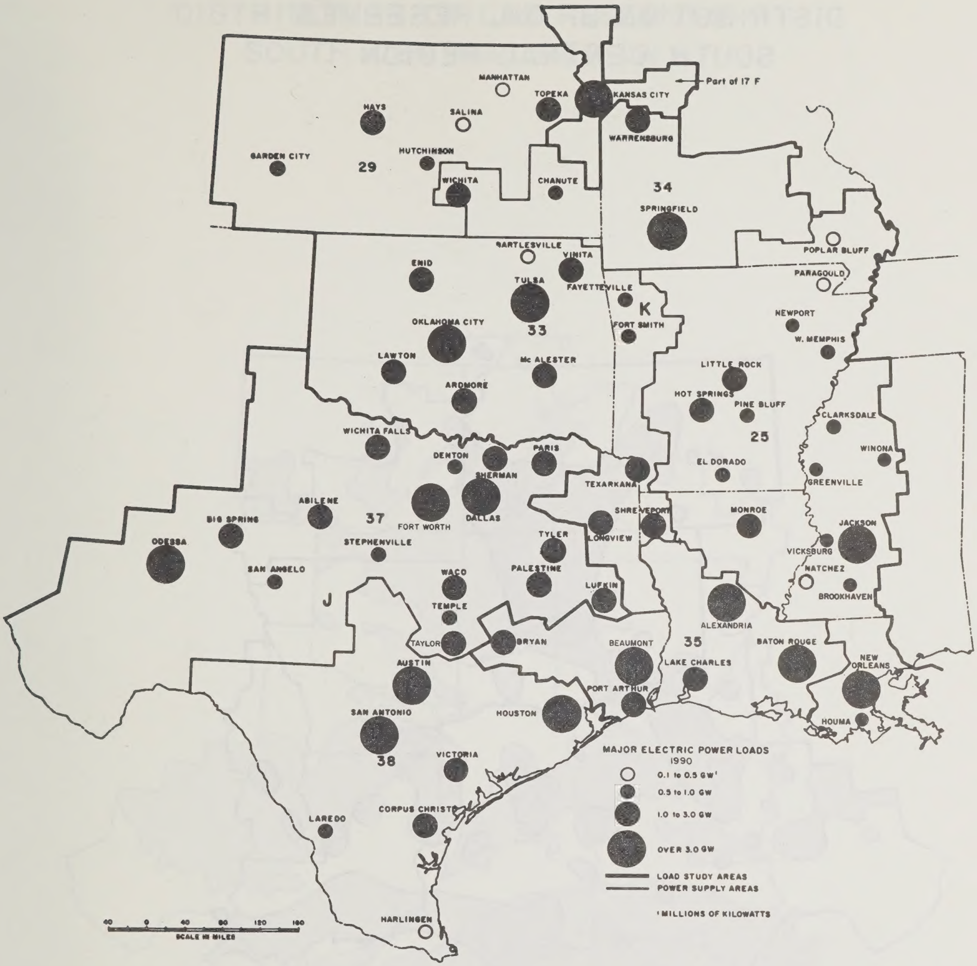
MAJOR ELECTRIC LOAD CENTERS
SOUTH CENTRAL REGION
1970

FIGURE 14



MAJOR ELECTRIC LOAD CENTERS
SOUTH CENTRAL REGION
1980

FIGURE 15



MAJOR ELECTRIC LOAD CENTERS
SOUTH CENTRAL REGION
1990

FIGURE 16

DISTRIBUTION OF OIL RESERVES
SOUTH CENTRAL REGION

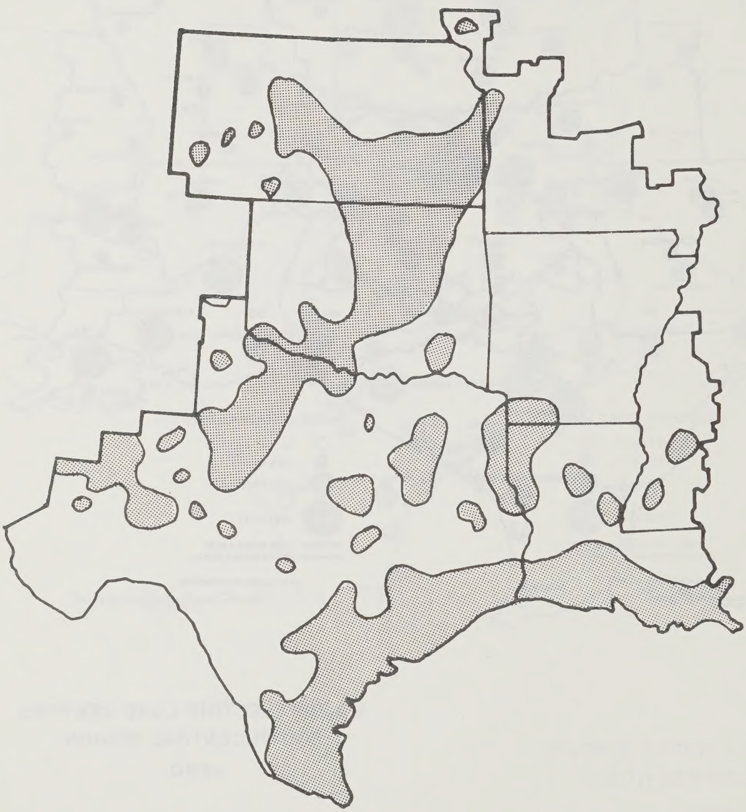


FIGURE 17

DISTRIBUTION OF GAS RESERVES
SOUTH CENTRAL REGION

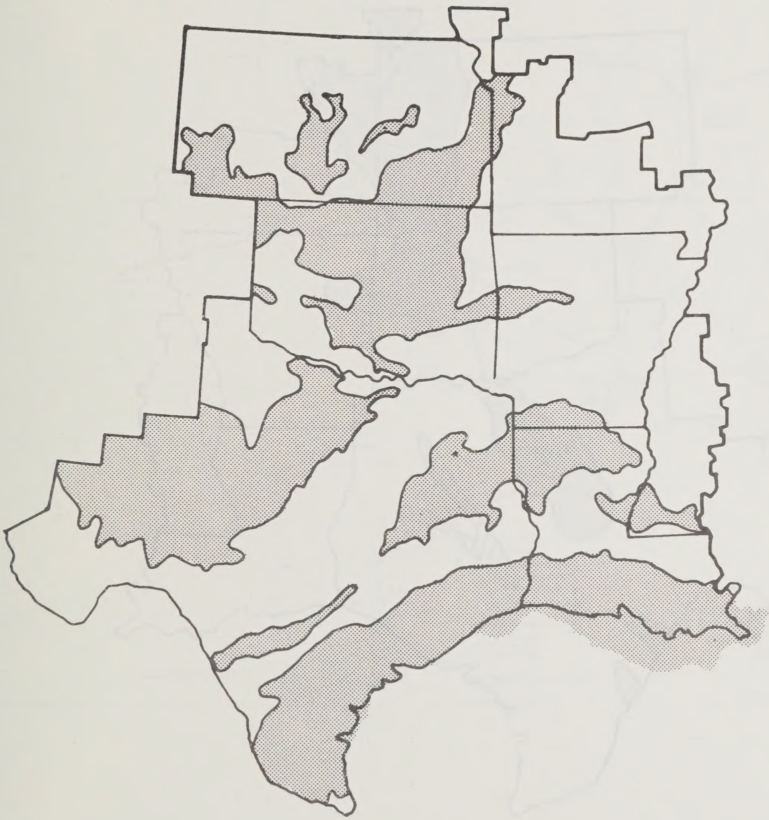


FIGURE 18

DISTRIBUTION OF COAL RESERVES
SOUTH CENTRAL REGION

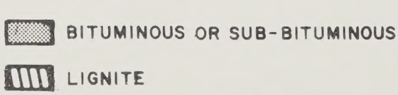


FIGURE 19

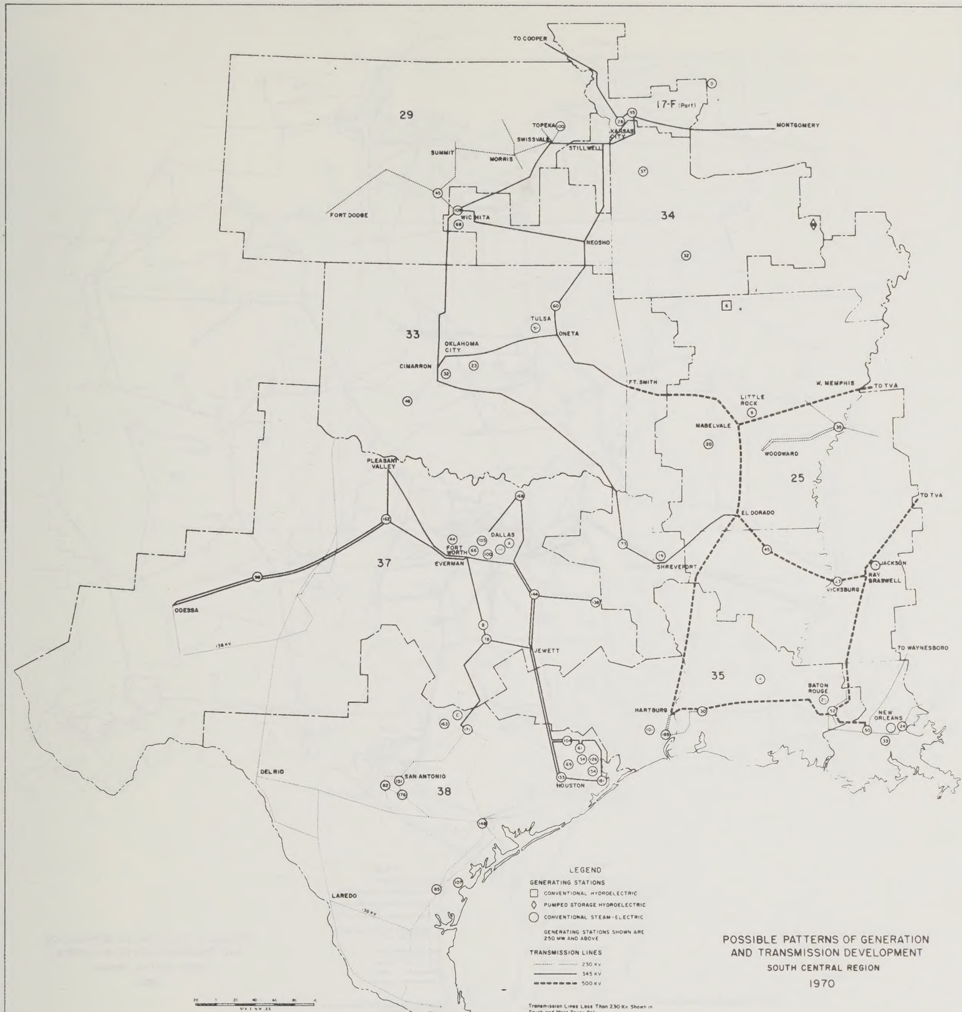
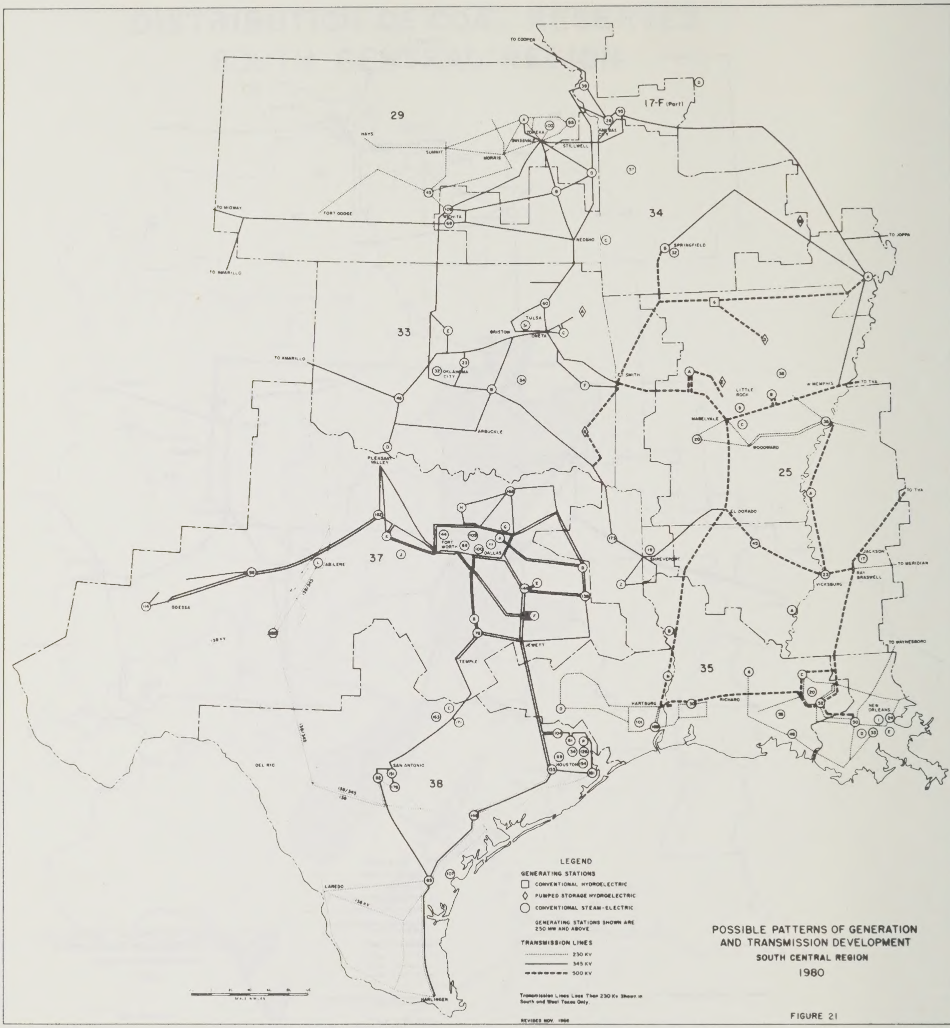
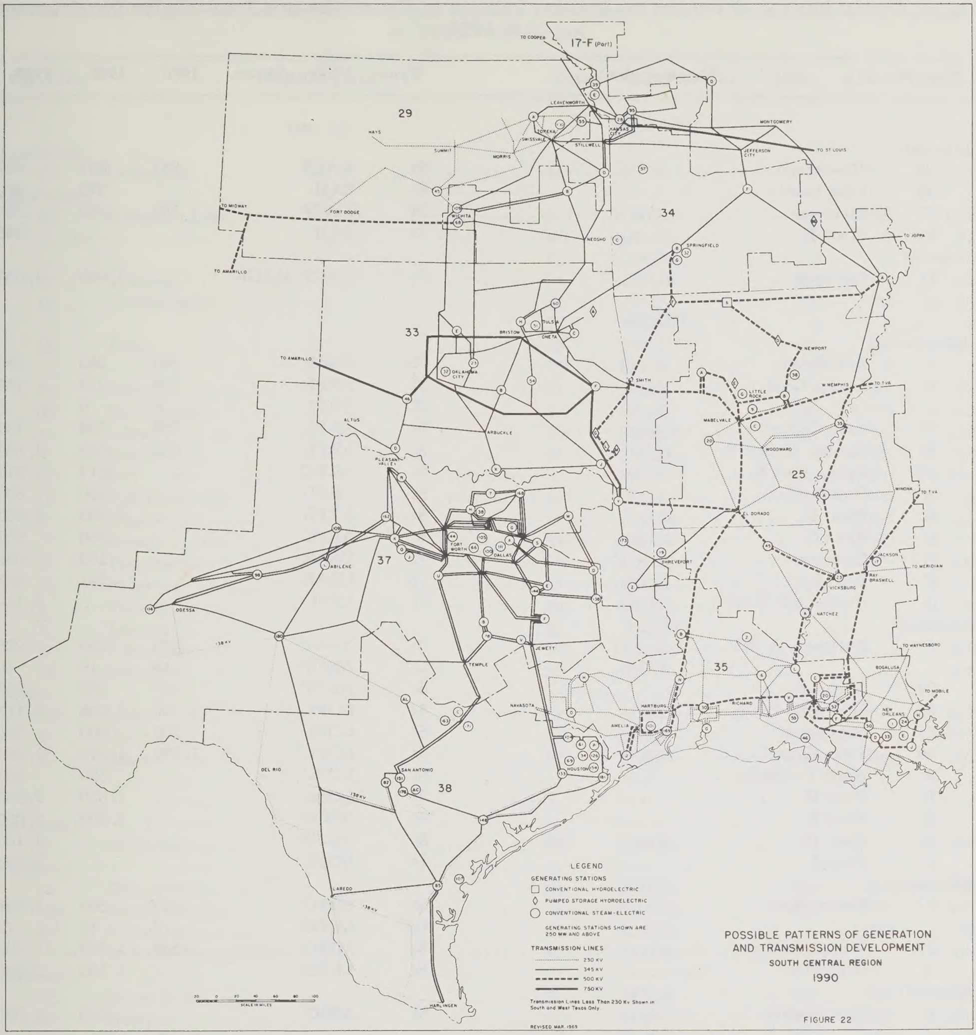


FIGURE 20

356-240 O—70——7


29
17-F (Part)
34
33
25
37
35
38
TO COOPER
TO MIDWAY
TO AMARILLO
TO JOPPA
TO TVA
TO MERIDIAN
TO WAYNESBORO
HAYS
SUMMIT
MORRIS
TOPEKA
KANSAS CITY
STILLWELL
FORT DODGE
WICHITA
NEOSHO
SPRINGFIELD
TULSA
BRISTOW
ONETA
OKLAHOMA CITY
ARBUCKLE
SMITH
LITTLE ROCK
MEMPHIS
MABELVALE
WOODWARD
PLEASANT VALLEY
EL DORADO
FORT WORTH
DALLAS
ABILENE
ODESSA
SHREVEPORT
JACKSON
VICKSBURG
RAY BRASWELL
TEMPLE
JEWETT
HARTBURG
RICHARD
NEW ORLEANS
HOUSTON
SAN ANTONIO
DEL RIO
LAREDO
HARLINGEN
LEGEND
GENERATING STATIONS
CONVENTIONAL HYDROELECTRIC
PUMPED STORAGE HYDROELECTRIC
CONVENTIONAL STEAM-ELECTRIC
GENERATING STATIONS SHOWN ARE 250 MW AND ABOVE
TRANSMISSION LINES
230 KV
345 KV
500 KV
Transmission Lines Less Than 230 Kv Shown in South and West Texas Only.
POSSIBLE PATTERNS OF GENERATION AND TRANSMISSION DEVELOPMENT
SOUTH CENTRAL REGION
1980
FIGURE 21



POSSIBLE PATTERNS OF GENERATION AND TRANSMISSION DEVELOPMENT
SOUTH CENTRAL REGION
1990

FIGURE 22

South Central Region—Plant List for Possible Patterns of Generation and Transmission Development to 1990

Plant No.	Name of plant	Type	Utility abbrev.	1970	1980	1990
	PSA 17–F					
Missouri:						
28	Hawthorne	St	KACP	857	857	857
39	Lake Road	St	SAJL	....	370	370
57	Montrose	St	KACP	563	563	563
E [1]	Plant E	St	SAJL	....	....	345
Kansas:						
D	LaCygne	St	KACP, KAGE	....	1,600	1,600
	PSA 25					
Arkansas:						
6	Bull Shoals	Hy	USAR	340	340	340
9	Lynch, Cecil	St	ARPL	239	239	239
		IC	ARPL	6	6	6
20	Lake Catherine	St	ARPL	739	739	739
35	Ritchie, Robert E.	St	ARPL	889	889	1,639
38	Bailey, Carl E.	St	AREC	....	317	317
A [2]	Russellville	St	ARPL	....	830	830
B	Plant B	St	ARPL	....	1,300	2,050
C	Plant C	St	ARPL	....	550	550
D	Optimus	PS	USAR	....	500	500
E	Petit Jean	PS	USAR	....	561	561
G	North Little Rock	St	ARPL	....	....	4,150
Louisiana:						
1	Patterson, A. B.	St	NEOP	226	226	226
		GT	NEOP	16	16	16
24	Michoud	St	NEOP	907	907	907
33	Nine Mile Point	St	LOPL	1,066	1,066	2,416
45	Sterlington	St	LOPL	300	300	300
50	Little Gypsy	St	LOPL	1,240	1,240	1,240
A	North Louisiana	St	LOPL	....	550	550
D	Plant D	St	LOPL	....	1,850	2,950
E	Plant E	St	NEOP	....	1,300	2,050
H	Plant H	St	NEOP	....	....	1,100
J	Plant J	St	LOPL	....	....	3,200
Mississippi:						
17	Brown, Rex	St	MIPO	390	390	1,658
		GT	MIPO	12	12	12
23	Wilson, Baxter	St	MIPO	550	1,300	1,300
A	Greenville	St	MIPO	....	1,500	2,600
Missouri:						
A	New Madrid	St	ASEC	....	500	1,000
	PSA 29					
Kansas:						
45	Hutchinson No. 2	St	KAPL	252	252	252
55	Lawrence	St	KAPL	....	620	620
100	Tecumseh	St	KAPL	346	346	346
A [3]	Unknown	St	KAPL	....	1,430	2,800

See footnotes at end of table.

South Central Region—Plant List for Possible Patterns of Generation and Transmission Development to 1990—Continued

Plant No.	Name of plant	Type	Utility abbrev.	1970	1980	1990
	PSA 33					
Louisiana:						
19	Lieberman	St	SOEP	277	277	277
Oklahoma:						
23	Horseshoe Lake	St	OKGE	888	888	888
		GT	OKGE	27	27	27
		IC	OKGE	2	2	2
32	Mustang	St	OKGE	504	504	504
46	Southwestern	St	PSOK	480	480	1,480
		IC	PSOK	6	6	6
51	Tulsa	St	PSOK	483	483	483
		IC	PSOK	8	8	8
54	Weleetka	St	PSOK	....	628	628
60	Northeastern	St	PSOK	600	1,173	2,273
A	Salina	PS	GRRD	....	520	520
B	Seminole	St	OKGE	....	1,125	3,025
C [3]	Port	St	PSOK	....	1,000	2,000
D	Red River	St	PSOK	....	500	1,000
E	Cresent	St	OKGE	....	1,325	3,195
F [3]	Keota	St	OKGE	....	1,500	5,135
G	Tuskahoma	PS	USAR	....	1,000	1,000
H	Fisher	St	PSOK	....	....	2,000
J [1]	Valliant	St	PSOK	....	....	1,000
K	Texoma	St	OKGE	....	....	1,500
L	Boktukola	PS	USAR	....	....	1,000
M	Sherwood	PS	USAR	....	....	500
Texas:						
173	Wilkes	St	SOEP	522	867	867
Y	Plant Y	St	SOEP	....	....	2,000
Z	Plant Z	St	SOEP	....	750	750
	PSA 34					
Arkansas:						
F	Mulladay	PS	USAR	....	....	485
Kansas:						
68	Gill, Murray	St	KAGE	348	348	348
109	Evans, Gordon	St	KAGE	518	518	518
B [1]	Redmond	St	KAGE	....	2,000	4,000
	Unk (SEKan or SWMo)	St	EMDE	....	....	500
Missouri:						
32	James River	St	SPRM	300	300	300
95	Sibley	St	MIPU	442	1,280	1,280
96	Taum Sauk	PS	UNEC	408	408	408
B	Plant B	St	SPRM	....	300	300
C	Asbury	St	EMDE	....	500	500
D	Thomas Hill	St	ASEC	465	465	465
	Unknown	St	MIPU	....	....	1,000
F [1]	Maries	St	ASEC	....	....	750
G [1]	Plant G.S	St	SPRM	....	....	700

See footnotes at end of table.

South Central Region—Plant List for Possible Patterns of Generation and Transmission Development to 1990—Continued

Plant No.	Name of plant	Type	Utility abbrev.	1970	1980	1990
	PSA 35					
Louisiana:						
2	Alexandria, City of	St	ALEX	....	....	630
6	Coughlin	St	CELE	483	483	483
20	Louisiana	St	GUSU	426	426	426
30	Nelson, Roy S	St	GUSU	920	1, 720	1, 720
46	Teche	St	CELE	....	869	869
52	Willow Glenn	St	GUSU	933	2, 298	3, 054
55	Bonin, "Doc"	St	LAFA	....	411	1, 011
B [1]	Toro	St	CELE	....	550	2, 100
C [1]	Plant C	St	GUSU	....	2, 120	6, 470
F	Plant F	St	GUSU	....	....	5, 675
G	Plant G	St	GUSU	....	....	1, 325
K	Plant K	St	GUSU	....	....	1, 512
L [1]	Torras	St	CELE	....	....	1, 500
Texas:						
101	Neches	St	GUSU	452	452	452
169	Sabine	St	GUSU	952	1, 532	2, 800
O	Lewis Creek	St	GUSU	....	1, 105	1, 680
N [1]	Bon Wier	St	GUSU	....	1, 060	2, 120
H	Plant H	St	GUSU	....	....	2, 081
J [1]	Plant J	St	GUSU	....	....	3, 025
	PSA 37					
Texas:						
38	Denton	St	DENT	....	....	388
44	Eagle Mountain	St	TEES	290	290	290
66	Handley	St	TEES	525	525	525
78	Lake Creek	St	TEPL	317	317	317
		IC	TEPL	6	6	6
98	Morgan Creek	St	TEES	833	833	833
		IC	TEES	2	2	2
100	Mountain Creek	St	DAPL	956	956	1, 471
105	North Lake	St	DAPL	700	700	700
109	Paint Creek	St	WETU	....	....	425
111	Parkdale	St	DAPL	327	327	327
114	Permian Basin	St	TEES	....	742	742
138	Stryker Creek	St	TEPL	675	675	675
		IC	TEPL	10	10	10
144	Trinidad	St	TEPL	413	413	413
		IC	TEPL	4	4	4
162	Graham	St	TEES	635	635	635
168	Valley	St	TEPL	725	1, 100	1, 100
180	San Angelo	St	WETU	....	375	600
A	Lake Hubbard	St	DAPL	375	1, 625	2, 625
B	Tradinghouse Creek	St	TEPL	565	2, 065	2, 065
D	Undesignated	St	Undesignated	....	2, 250	2, 250
E	Undesignated	St	TEPL	....	750	2, 500
F	Big Brown	St	TEES,TEPL, DAPL	....	1, 150	1, 150
G	Lake Lavon	St	GARL	....	316	971
H	Undesignated	St	TEPL	....	750	3, 250
J	Miller	St	BREP	....	381	796
K	Undesignated	St	TEES	....	1, 500	3, 500
L	Undesignated	St	WETU	....	275	575
Q [1]	Undesignated	St	TEES	....	....	1, 500
R	Undesignated	St	TEES	....	....	1, 500

South Central Region—Plant List for Possible Patterns of Generation and Transmission Development to 1990—Continued

Plant No.	Name of plant	Type	Utility abbrev.	1970	1980	1990
	PSA 37					
Texas—Continued						
S	Undesignated	St	DAPL			2,000
T	Undesignated	St	TEPL			1,500
U	Undesignated	St	TEPL			2,500
V	Undesignated	St	Undesignated			1,000
W	Undesignated	St	Undesignated			750
	PSA 38					
Texas:						
34	Deepwater	St	HOLP	335	335	335
61	Greens Bayou	St	HOLP	375	375	375
69	Clarke, Hiram O	St	HOLP	210	210	210
		Gt	HOLP	90	90	90
82	Leon Creek	St	SAAN	264	264	264
85	Hill, Lon C	St	CEPL	548	548	548
104	Wharton, T. H	St	HOLP	323	323	323
		GT	HOLP	15	15	15
107	Nueces Bay	St	CEPL	258	258	258
126	Bertron, Sam	St	HOLP	826	826	826
		GT	HOLP	30	30	30
133	Parish, W. A	St	HOLP	1,240	1,240	1,240
		GT	HOLP	30	30	30
148	Victoria	St	CEPL	528	528	528
151	Tuttle, W. B	St	SAAN	494	494	494
154	Webster	St	HOLP	614	614	614
		GT	HOLP	15	15	15
163	Holly Street	St	AUST	391	391	391
171	Gideon, Sim	St	LOCR	250	565	565
176	Braunig, Victor	St	SAAN	898	898	898
181	Robinson, P. H	St	HOLP	1,534	1,534	1,534
		GT	HOLP	15	15	15
C	Decker Creek	St	AUST	300	300	300
P	Cedar Bayou	St	HOLP		1,500	1,500
AC [1]	Calaveras	St	SAAN	([4])	([4])	([4])
AL [1]	L. B. Johnson Lake	St	LOCR	([4])	([4])	([4])

[1] Possible nuclear plant.
[2] Nuclear plant under construction.
[3] Possible part nuclear plant.
[4] Not yet designated.

Ownership List for Possible Patterns of Generation and Transmission Development to 1990

Utility abbreviations	Type owner	Utilities
		Arkansas
AREC	Coop	Arkansas Electric Cooperative Corporation
ARPL	Pri	Arkansas Power & Light Company
USAR	Fed	U.S. Army
		Kansas
EMDE	Pri	Empire District Electric Company, The
KACP	Pri	Kansas City Power & Light Company
KAGE	Pri	Kansas Gas & Electric Company
KAPL	Pri	Kansas Power & Light Company, The
		Louisiana
ALEX	Mun	Alexandria
CELE	Pri	Central Louisiana Electric Co., Inc.
GUSU	Pri	Gulf States Utilities Company
LAFA	Mun	Lafayette
LOPL	Pri	Louisiana Power & Light Company
NEOP	Pri	New Orleans Public Service, Inc.
SOEP	Pri	Southwestern Electric Power Company
		Mississippi
MIPO	Pri	Mississippi Power & Light Company
		Missouri
ASEC	Coop	Associated Electric Cooperative, Inc.
EMDE	Pri	Empire District Electric Company, The
KACP	Pri	Kansas City Power & Light Company
MIPU	Pri	Missouri Public Service Company
SAJL	Pri	St. Joseph Light & Power Company
SPRM	Mun	Springfield
UNEC	Pri	Union Electric Company
		Oklahoma
GRRD	State	Grand River Dam Authority
OKGE	Pri	Oklahoma Gas & Electric Company
PSOK	Pri	Public Service Company of Oklahoma
USAR	Fed	U.S. Army
		Texas
AUST	Mun	Austin
BREP	Coop	Brazos Electric Power Cooperative, Inc.
CEPL	Pri	Central Power & Light Company
DAPL	Pri	Dallas Power & Light Company
DENT	Mun	Denton
GARL	Mun	Garland
GUSU	Pri	Gulf States Utilities Company
HOLP	Pri	Houston Lighting & Power Company
LOCR	State	Lower Colorado River Authority
SAAN	Mun	San Antonio
SOEP	Pri	Southwestern Electric Power Company
TEES	Pri	Texas Electric Service Company
TEPL	Pri	Texas Power & Light Company
WETU	Pri	West Texas Utilities

APPENDIX A

STUDY OF PEAK ELECTRIC LOAD DURATION DURING A HEAT STORM COINCIDENT WITH A DROUTH PERIOD OF RECORD

Report of Task Force on Load Forecast SCRAC Meeting

July 25, 1967—Dallas, Texas

The study assignment to the Task Force is delineated in the fourth paragraph of the Minutes of the SCRAC Meeting of April 25, 1967. The Task Force was instructed in the April 25th meeting to determine the duration of heat storms experienced in the South Central Region and to review the shape of daily load curves that would result during heat storms of record, and to recommend load and temperature data that should be used by other SCRAC committees in studying the application of low load factor hydro, pumped storage, diversity capacity, and thermal generation sources to serve summer peak loads.

Summer loads experienced in the South Central Region are predominantly temperature responsive. Persistent periods of high temperatures and the resultant above-normal peak loads will likely occur during periods of below-normal rainfall. It is, therefore, fundamental that load conditions corresponding to those that would exist during periods of persistent high temperatures coincident with drouth weather conditions be used in studying the application of power sources to serve summer peak loads. To do otherwise could result in incorrect conclusions being reached as to the economy, reliability, and availability of various types of capacity (particularly low load factor hydro and pumped storage) for serving loads experienced during the summer months.

Special studies were made of the correlation of daily loads and daily temperatures for the OG&E system covering July and August of 1954, 1964, and 1966. The objective was to determine if we could accurately predict the shape of the daily load curve if heat storm and drouth weather conditions that prevailed in 1954 and 1936 should recur. It is our conclusion that we can predict with a high degree of accuracy the hourly loads that would exist during July and August if drouth and temperature conditions typical of those that prevailed in 1936 and 1954 should recur. This same conclusion should apply to other electric systems with load characteristics similar to that of OG&E.

Figures 1, 2, and 3 show the OG&E daily load diagrams for the peak load day of 1966, 1954, and 1964, respectively.

	Date	Peak load MW	Maximum temperature	Degree hours	Load factor
Figure 1	7–19–66	1, 574	108	2, 200	79. 1
Figure 2	7–12–54	495	107	2, 215	79. 1
Figure 3	8– 6–64	1, 326	106	2, 227	80. 3

It should be noted that the basic shapes of the three daily load diagrams are essentially identical and there is very close correlation between load and temperature. Daily load and temperature curves for the entire period of July and August of 1954, 1964, and 1966 (Figures 4, 5, and 6) were prepared, and this same similarity of the basic daily load shapes and the correlation between load and temperature is evident throughout the two-month periods for the three years studied. For weekdays the load varies essentially directly with temperatures from 6:00 A.M. to 3:00 P.M. The increase in load amounts to approximately 1½% for each degree increase in temperature. Copies of the daily load and daily temperature curves consisting of sixty-nine

11″ x 14″ sheets printed on an IBM 1800 Computer (Figures 4, 5, and 6) are not included as a part of this report, but copies are being furnished the FPC office in Fort Worth.

Figures 7 and 8 and the table below show temperature data for Oklahoma City. The most adverse temperature conditions during recent times occurred in 1954 and 1936.

Oklahoma City Temperature Data

Year	No. of days 100° F. or higher	No. consecutive days 100° F. or higher	No. of days 95° F. or higher	No. consecutive days 95° F. or higher
1936	43	22	67	27
1954	41	10	71	29
1964	21	8	46	15
1966	23	19	44	20

Accurate curves of daily load that would exist for July and August based on 1936 weather conditions could be developed for each system having predominantly temperature responsive loads similar to that of OG&E. It appears probable that accurate curves of daily load could also be developed for selected areas such as the Southwest Power Pool and the Texas areas. It is the recommendation of the Task Force that daily load curves for individual systems or selected areas based on temperature and weather conditions typical of those prevailing in 1936 be used for studying the application of low load factor hydro, pumped storage, diversity capacity, and thermal generation for carrying July and August peak loads.

This report is submitted by the Task Force on Load Forecast, consisting of C. W. Anthony, G. E. Schmitt, and W. M. Brewer, on July 25, 1967.

/S/ C. W. Anthony,
Chairman.

DAILY LOAD DIAGRAM

TRANSACTIONS		PEAK HOUR MWH	TOTAL DAY MWH
TOTAL NET GENERATION			
SPA 31	PURCHASE		
SPA PEAKING	PURCHASE		
AP&L "E" 31	PURCHASE		
AP&L "E" 34	PURCHASE		
	PURCHASE		
	PURCHASE		
	PURCHASE		
AP&L "E" 34	SALE		
AP&L "C"	SALE		
	SALE		
	SALE		
	SALE		
TRANSPORTATION LOSS			
INADVERTENT	IN + OUT −		
SYS. LOAD TODAY	M		
SYS LOAD YEAR AGO	M		
INCREASE (+) DECREASE (−)			

OKLAHOMA CITY OFFICIAL WEATHER				
PERIOD	SKY CONDITIONS AM	SKY CONDITIONS PM	TEMPERATURE MAX	TEMPERATURE MIN
TODAY			*105°	79°
YEAR AGO				

SYSTEM LOAD FACTOR TODAY 74.1 %, YEAR AGO %

MAXIMUM DEMAND: MW

PREDICTED MAX DEMAND: MW

ELECTRIC TIME ERROR @ NOON SECS SLOW FAST

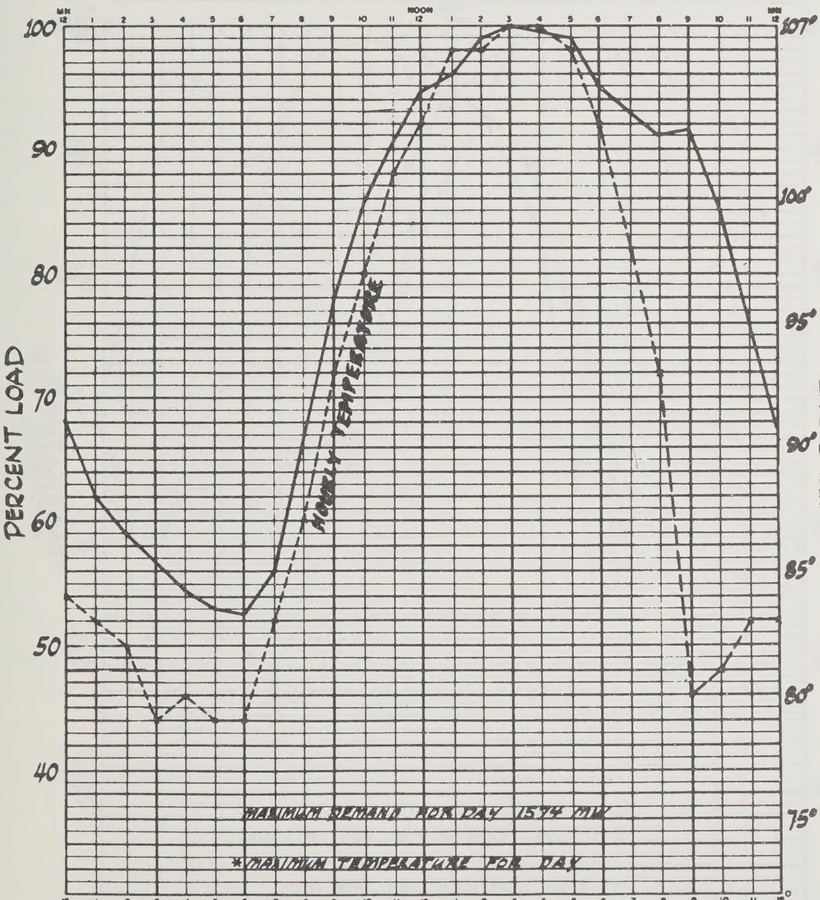
TESTS:

PEAK HOUR PLANT CAPABILITY REDUCTION:

TOTAL MW

DEGREE-HRS = 2200

OTHER PLANTS IN SERVICE TODAY:			
ARBUCKLE —	MWH	SHATTUCK —	MWH
BELLE ISLE -	MWH	WOODWARD —	MWH
BYNG —	MWH	WOODWARD GT -	MWH
OSAGE —	MWH	ENID GT —	MWH



PREPARED BY TRH APPROVED BY ______ DAY 19 DATE JULY 19 66

OKLAHOMA GAS AND ELECTRIC CO. 7/10/67 TUESDAY

FIGURE 1

DAILY LOAD DIAGRAM

TRANSACTIONS	PEAK HOUR MWH	TOTAL DAY MWH
TOTAL NET GENERATION		
SPA 3.1 PURCHASE		
SPA PEAKING PURCHASE		
AP&L "E" 3.1 PURCHASE		
AP&L "E" 3.4 PURCHASE		
PURCHASE		
PURCHASE		
PURCHASE		
AP&L "E" 3.4 SALE		
AP&L "C" SALE		
SALE		
SALE		
SALE		
TRANSPORTATION LOSS		
INADVERTENT IN + OUT −		
SYS. LOAD TODAY M		
SYS LOAD YEAR AGO M		
INCREASE (+) DECREASE (−)		

OKLAHOMA CITY OFFICIAL WEATHER

PERIOD	SKY CONDITIONS AM	SKY CONDITIONS PM	TEMPERATURE MAX	TEMPERATURE MIN
TODAY			*107°	78°
YEAR AGO				

SYSTEM LOAD FACTOR TODAY 79.1 %, YEAR AGO %

MAXIMUM DEMAND: MW

PREDICTED MAX DEMAND: MW

ELECTRIC TIME ERROR @ NOON: SECS SLOW FAST

TESTS:

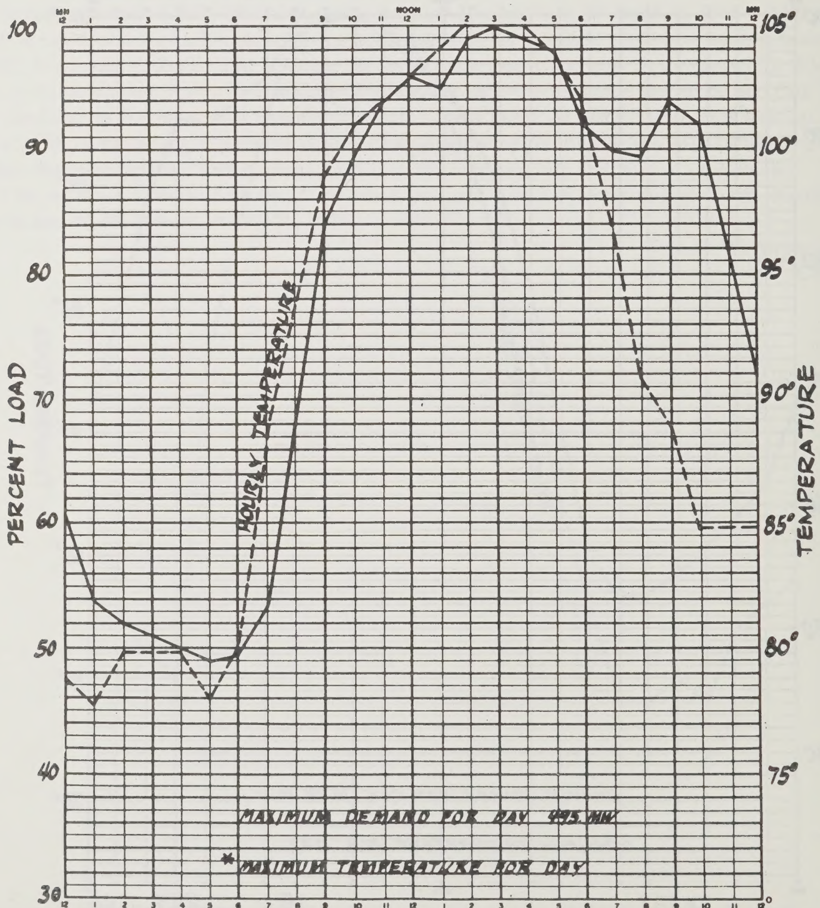
PEAK HOUR PLANT CAPABILITY REDUCTION:

TOTAL MW

DEGREE-HRS : 2215

OTHER PLANTS IN SERVICE TODAY:

ARBUCKLE —	MWH	SHATTUCK —	MWH
BELLE ISLE —	MWH	WOODWARD —	MWH
BYNG —	MWH	WOODWARD GT —	MWH
OSAGE —	MWH	ENID GT —	MWH



PREPARED BY TRH APPROVED BY ______ DAY 12 DATE JULY 19 54

OKLAHOMA GAS AND ELECTRIC CO.
7/10/67

FIGURE 2

MONDAY

DAILY LOAD DIAGRAM

TRANSACTIONS	PEAK HOUR MWH	TOTAL DAY MWH
TOTAL NET GENERATION		
SPA 3.1 PURCHASE		
SPA PEAKING PURCHASE		
AP&L "E" 3.1 PURCHASE		
AP&L "E" 3.4 PURCHASE		
PURCHASE		
PURCHASE		
PURCHASE		
AP&L "E" 3.4 SALE		
AP&L "C" SALE		
SALE		
SALE		
SALE		
TRANSPORTATION LOSS		
INADVERTENT IN + OUT −		
SYS. LOAD TODAY M		
SYS. LOAD YEAR AGO M		
INCREASE (+) DECREASE (−)		

OKLAHOMA CITY OFFICIAL WEATHER

PERIOD	SKY CONDITIONS AM	SKY CONDITIONS PM	TEMPERATURE MAX	TEMPERATURE MIN
TODAY			*106°	78°
YEAR AGO				

SYSTEM LOAD FACTOR TODAY 80.3 %; YEAR AGO %

MAXIMUM DEMAND: MW

PREDICTED MAX DEMAND: MW

ELECTRIC TIME ERROR @ NOON SECS SLOW FAST

TESTS:

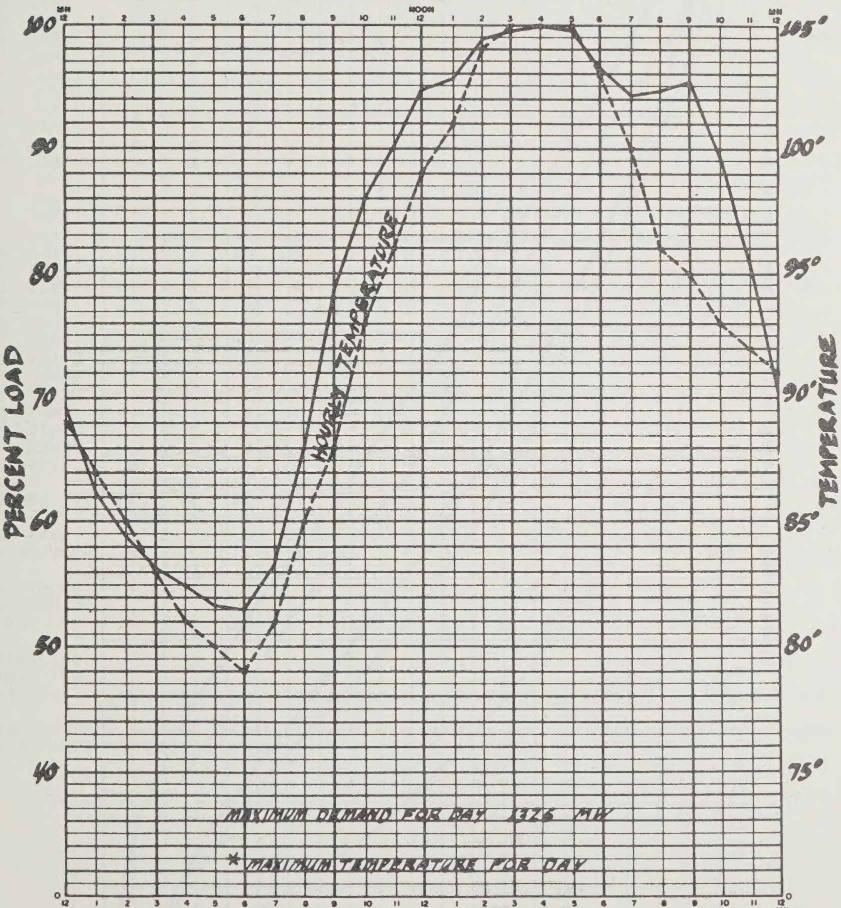
PEAK HOUR PLANT CAPABILITY REDUCTION:

TOTAL MW

DEGREE-HRS = 2227

OTHER PLANTS IN SERVICE TODAY:

ARBUCKLE ——	MWH	SHATTUCK ——	MWH
BELLE ISLE —	MWH	WOODWARD ——	MWH
BYNG ——	MWH	WOODWARD GT —	MWH
OSAGE ——	MWH	ENID GT ——	MWH



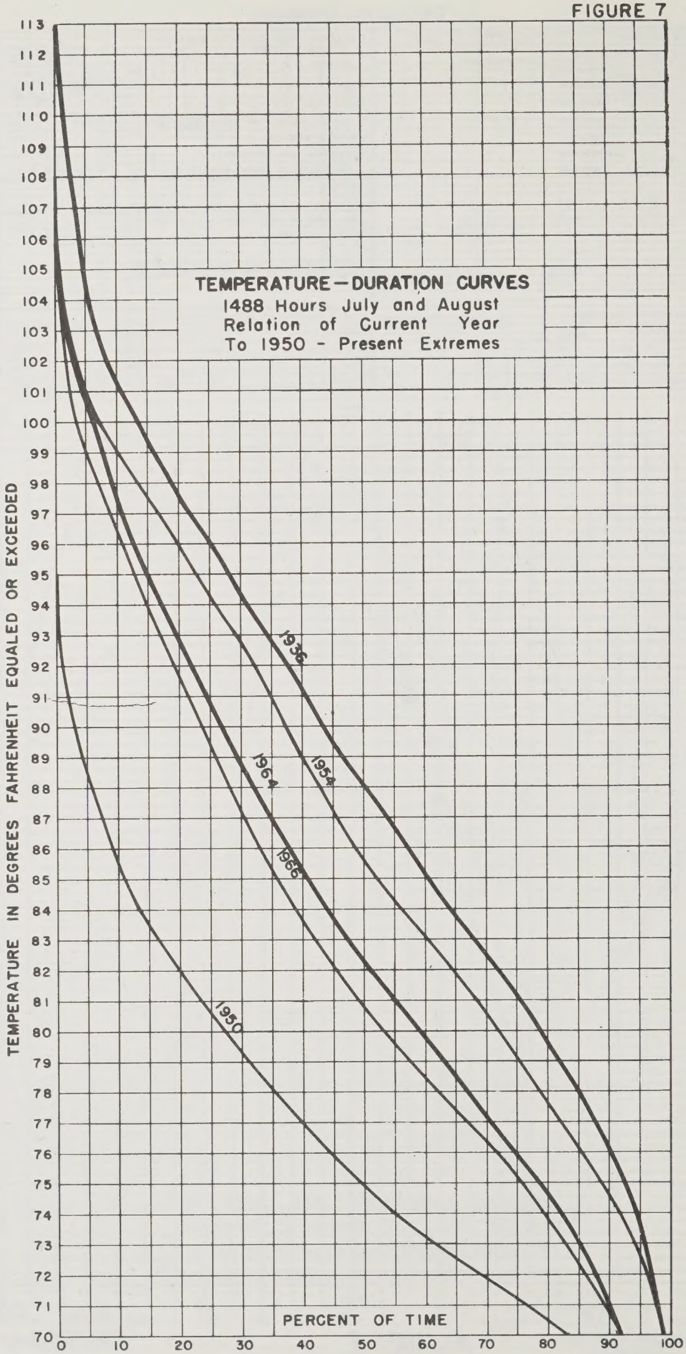
PREPARED BY TRH APPROVED BY ______ DAY 6 DATE AUG 19 64

OKLAHOMA GAS AND ELECTRIC CO. 7/10/67

FIGURE 3

THURSDAY

FIGURE 7



TEMPERATURE — DURATION CURVES
1488 Hours July and August
Relation of Current Year
To 1950 - Present Extremes
TEMPERATURE IN DEGREES FAHRENHEIT EQUALED OR EXCEEDED
PERCENT OF TIME
1936
1954
1964
1966
1950
113
112
111
110
109
108
107
106
105
104
103
102
101
100
99
98
97
96
95
94
93
92
91
90
89
88
87
86
85
84
83
82
81
80
79
78
77
76
75
74
73
72
71
70
0
10
20
30
40
50
60
70
80
90
100

FIGURE 8

OKLAHOMA CITY SUMMER WEATHER DATA
WILL ROGERS WORLD AIRPORT WEATHER STATION

NUMBER OF DAYS THAT MAXIMUM TEMPERATURES EQUALED COLUMN HEADINGS

YEAR	1/ DEGR DAYS	DEGREES FAHRENHEIT 100	101	102	103	104	105	106	107	108	109	110	111	112	113	TOTAL DAYS
1930		8	2	3	2	3	2	1								21
1931		5	3	-	3	1										12
1932		2	1	1												4
1933		5	2	1	4	2	-	-	1							15
1934	2280	7	7	13	7	6	1	3	1							45
1935	2016	-	3	3	5	-	1									12
1936	2330	8	6	8	4	5	2	-	3	2	2	1	-	1	1	43
1937	2268	5	6	3	-	3	2	1	1							21
1938	2301	1	2													3
1939	2266	4	5	2	-	3	1	-	1							16
1940	1884	1	1													2
1941	2207	3	2	-	1	1										7
1942	2031	1														1
1943	2161	3	7	4	5	4	4	1								28
1944	2166	5	3	6	2											16
1945	1933	2														2
1946	2070	6	3	4	1	2	1	1	1							19
1947	2192	4	2	2	1	4	4	3								20
1948	2090	3	2	1												6
1949	2035	-	1													1
1950	1905															-
1951	2061	4	3	4	1	-	3	1	1							17
1952	2086	7	3	2	4	-	-	1	1							18
1953	2130	8	2	1	-	4	2	1								18
1954	2249	7	11	10	6	1	3	1	2							41
1955	2020															-
1956	2128	9	2	2	4	3	1	2	2							25
1957	1889	3	-	1												4
1958	2037	-	1													1
1959	1980															-
1960	2010	1														1
1961	1888															-
1962	2269	2	2	2	-	3	-	2								11
1963	2447	4	3	6	2	-	1									16
1964	2129	2	4	3	2	3	4	3								21
1965	2247	5	5	3	1											14
1966	2015	10	4	1	2	3	-	-	2	1						23
37 YEARS		135	98	86	57	51	32	21	16	3	2	1	0	1	1	504
NO OF YEAR TEMP OCCURRED		30	29	24	19	17	15	13	11	1	1	1	0	1	1	
NO OF YEAR THIS TEMP OR HIGHER		33	30	26	22	21	19	17	11	2	1	1	1	1	1	
PROBABILITY OF THIS TEMP OR HIGHER		.892	.811	.703	.595	.568	.514	.459	.297	.054	.027	.027	.027	.027	.027	

IN THE 33 YEARS WHEN TEMPERATURES WERE 100 DEGREES F. OR HIGHER, THE AVERAGE NUMBER OF DAYS IN THIS TEMPERATURE RANGE 15.27 PER YEAR 504/33

$$1/\ \text{DEGREE DAYS} \quad \frac{0.4\ (\text{SUM OF 4 DRY-BULB AND 4 WET-BULB READINGS})\ 60}{4} - 60$$

APPENDIX B

TEMPERATURE—LOAD CHARACTERISTICS

SOUTHWEST POWER POOL

By T. R. Hoke, Oklahoma Gas & Electric Company

A report on temperature-load characteristics of the Oklahoma Gas and Electric Company was presented to the Sixth Meeting of the South Central Regional Advisory Committee on July 25, 1967. At the Committee's request, and with Mr. Bill Hulsey's cooperation, this study has been expanded to cover the Southwest Power Pool.

The purpose of this study is to determine the shape and duration of the hourly load curve that would result from a reoccurrence of the heat storms of 1936 or 1954.

Conclusion

Based on historical experience, a heat storm of the proportions of 1936 or 1954 would produce one or more periods of five successive days with essentially peak load each day. The principal change in the shape of daily load curves since 1954 has been elimination of the troughs at 1:00 p.m. and 7:00 p.m. producing longer duration of peak or near peak daily load.

Recommendation

Long-range studies of low load-factor sources should be based on the occurrence of five successive days of peak load. The historic hourly load shape of 1954 peak week, with smoothing to eliminate the 1:00 p.m. and 7:00 p.m. troughs, may be used. Alternatively, the average hourly load shape for the month of July, 1954, may be smoothed and applied for five successive days. The load shape recommended is in percent of peak load and may be applied to any forecast.

Procedure

Hourly loads for July and August, 1954, and 1966, were obtained for the total Southwest Power Pool, Oklahoma Gas and Electric Company, Southwestern Electric Power Company, and the Middle South System.

Hourly dry-bulb temperatures for the same periods were also determined for:

Beaumont, Texas
Jackson, Mississippi
Kansas City, Missouri (1966 only)
Little Rock, Arkansas
New Orleans, Louisiana
Oklahoma City, Oklahoma (also 1936)
Shreveport, Louisiana
Wichita, Kansas

In total, these data comprise 11,924 hourly loads and 23,848 hourly temperatures.

Computer analysis of this mass of data confirms that peak-period loading of the Southwest Power Pool is a temperature-responsive mechanism. Results are presented graphically for the peak week-day periods of 1954 and 1966 for each of the participating systems in Figures 1 through 8. Note that the temperature scales are different for each chart. The computer program forces the maximum-minimum temperature range to plot over the maximum-minimum load range in each case. The plotting range is determined from the two-month period, not just the five days shown.

The total Southwest Power Pool load is correlated with eight area temperatures in Figures 1 and 2. It is apparent that 1954 was not only hotter than 1966, but that high temperatures and loads were sustained for the entire week.

Figures 2 through 8 show that OG&E, SWEP, and Middle South respond similarly to temperature extremes.

A comparison of the average hourly load shapes for 1954 and 1966 for the four participants is plotted in Figures 9 through 12. In each case, the 1954 curve has a broader shape above 75 percent load but has troughs at 1:00 p.m. and 7:00 p.m. The wider shape is due to the greater temperature duration of 1954, and would be reproduced in any year with similar temperatures. The reduced 1:00 p.m. and 7:00 p.m. troughs in the 1966 load shapes indicate a trend to longer persistence of daily peaks.

Temperature-duration curves for OG&E are shown in Figure 13 for the years under study, as well as 1936, the hottest year of record. These curves are indicative of other companies' experience in this area.

In Figure 14, the hottest Oklahoma City week-day periods of 1954 and 1966 are compared with the hottest five-day period in 1936.

This study was limited to dry-bulb temperatures because of data availability. However, analysis of OG&E data has shown that humidity and the "THI Comfort Index" have little effect on peak load. The total energy consumption for the summer period does correlate well with the number of THI degree-days experienced.

In Oklahoma, high temperatures are always accompanied by low humidity. During the 10 years, 1954–1964, temperatures of 100° or over were recorded for 398 hours. The accompanying humidity for 329, or 83 percent, of these hours was in the range of 0–29 percent, with the remaining 69 hours all below 49 percent. For temperatures over 105°, humidity was always below 29 percent.

Hourly humidity readings are plotted with OG&E load and temperatures for the peak week of 1954 on Figure 4.

Humidity obviously is a much different factor in New Orleans and Beaumont, but neither of these cities experiences temperatures over 100°

Tom Hoke,
Oklahoma Gas and Electric Company.

October 16, 1967.

356-240 O—70——8

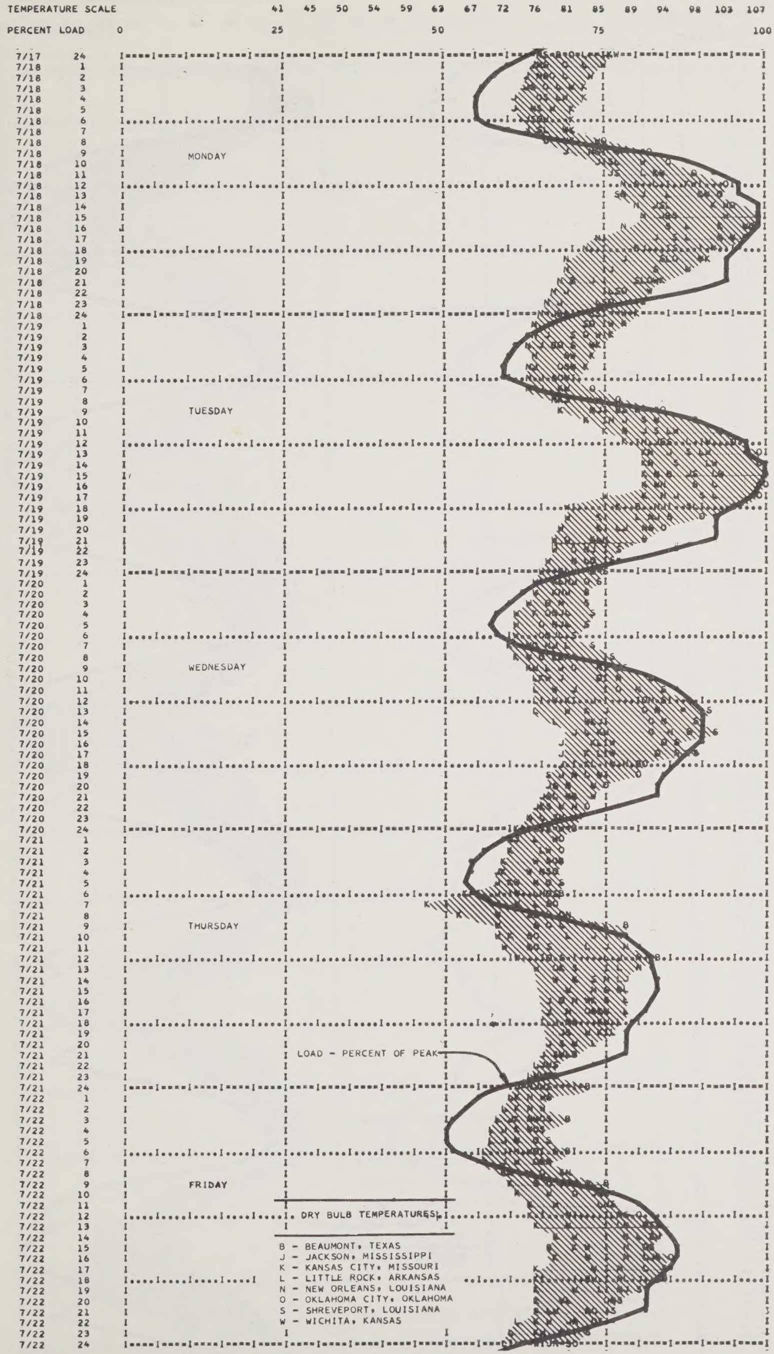
LIST OF FIGURES

SWPP LOADS VS AREA TEMPERATURES, JULY & AUGUST, 1966

LOAD RANGE 5146MW TO 12691MW

TEMPERATURE RANGE 55 DEGREES TO 107 DEGREES

FIGURE I

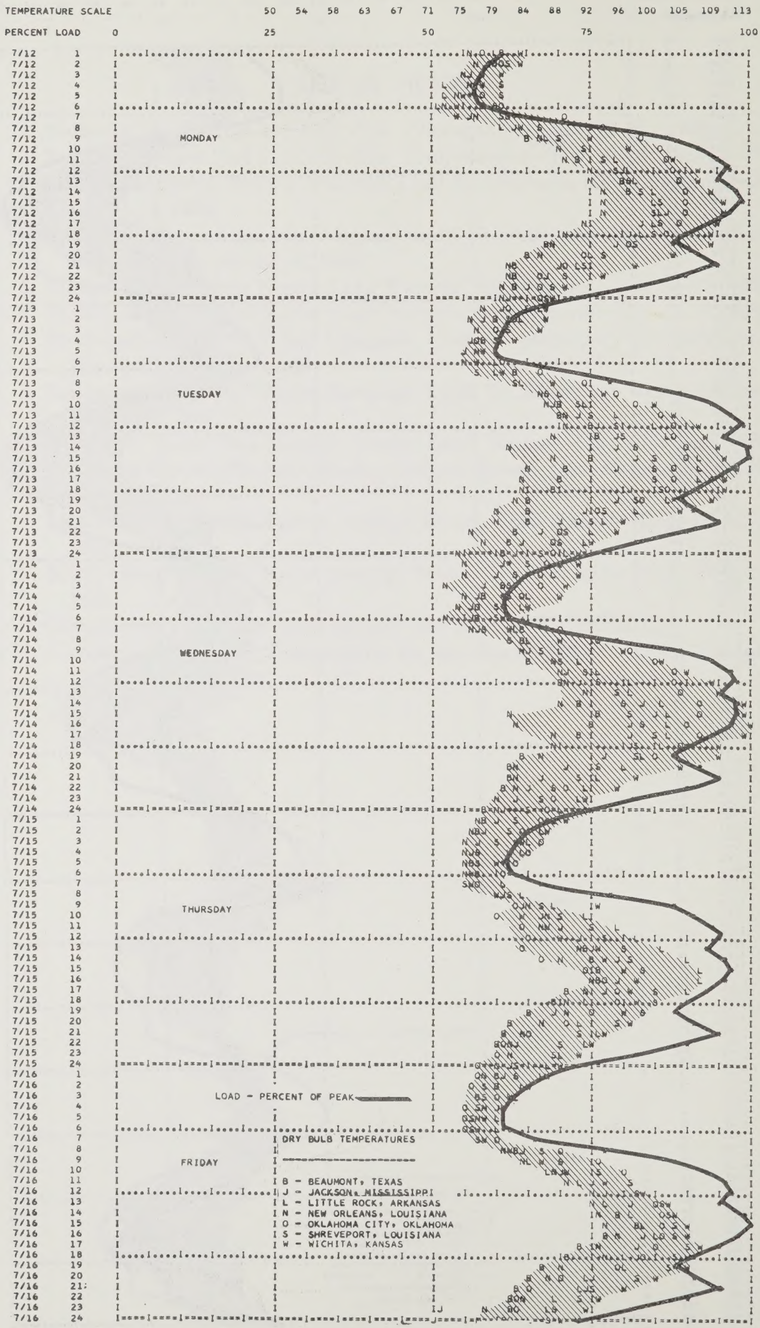


SW POWER POOL LOADS VS AREA TEMPERATURES, JULY, 1954

LOAD RANGE 1896MW TO 3823MW

TEMPERATURE RANGE 71 DEGREES TO 113 DEGREES

FIGURE 2

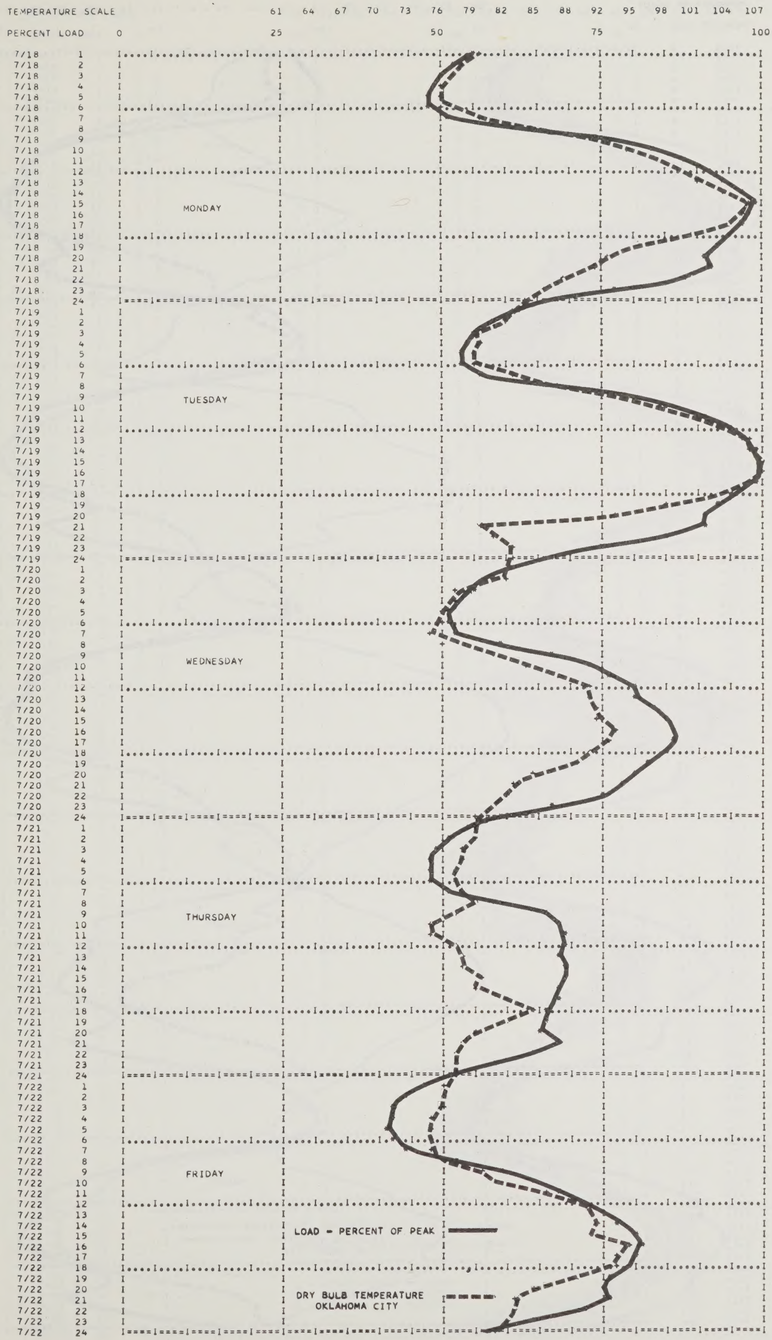


OKLAHOMA GAS & ELECTRIC COMPANY, JULY, 1966

LOAD RANGE 579MW TO 1574MW

TEMPERATURE RANGE 68 DEGREES TO 107 DEGREES

FIGURE 3

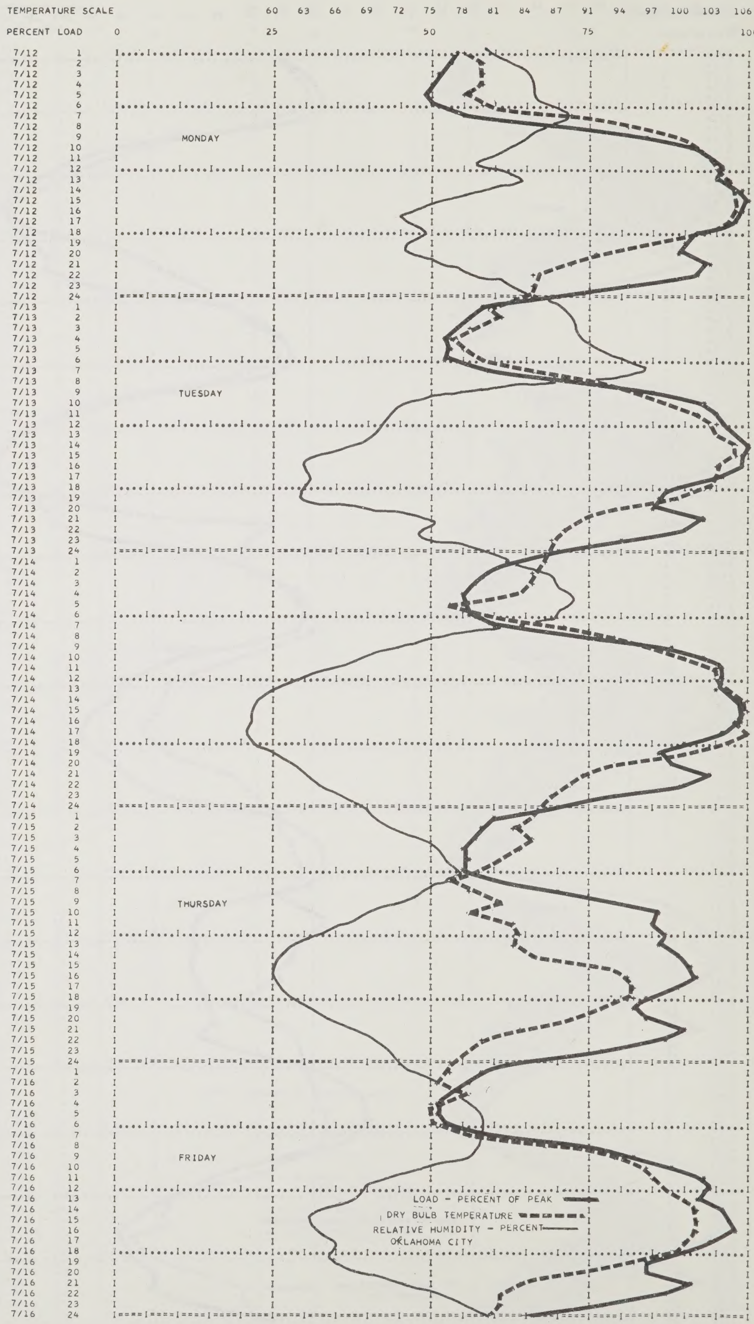


OKLAHOMA GAS & ELECTRIC COMPANY, JULY, 1954

LOAD RANGE 199MW TO 495MW

TEMPERATURE RANGE 69 DEGREES TO 106 DEGREES

FIGURE 4

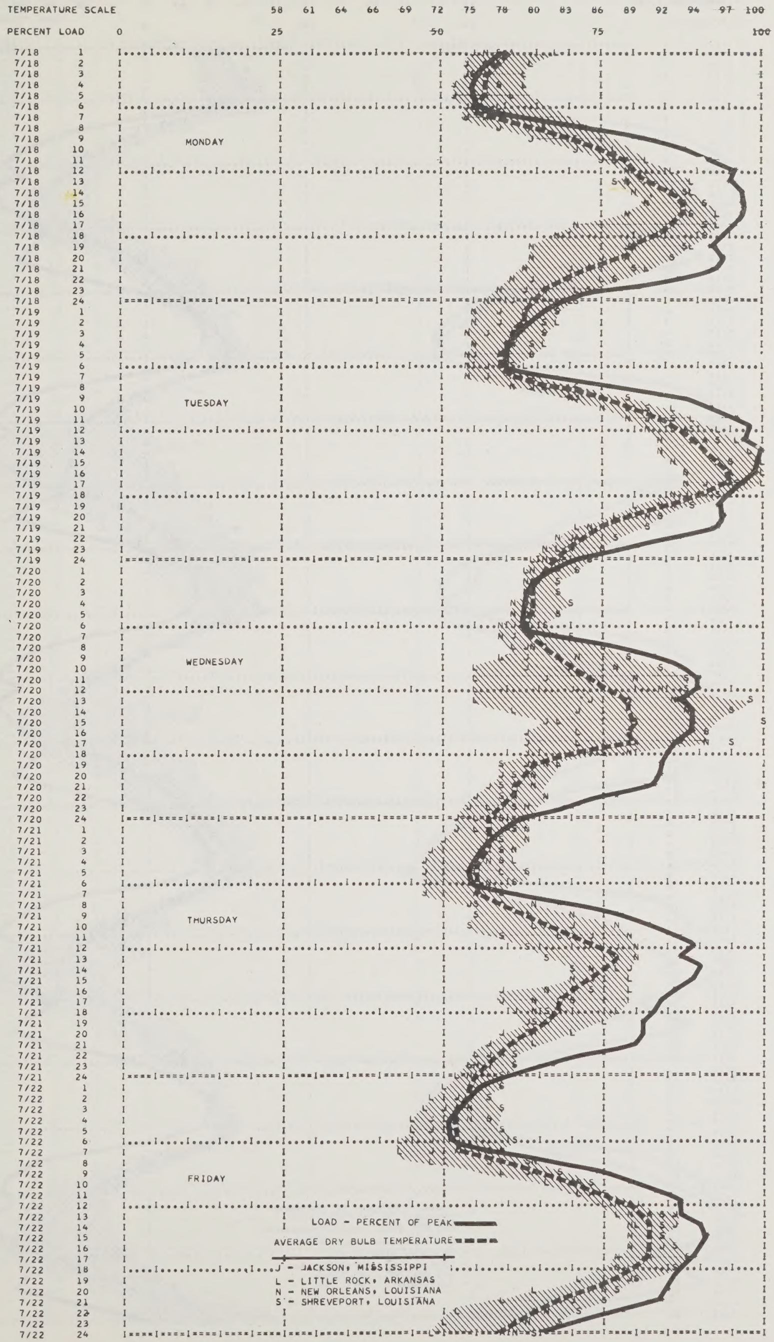


MIDDLE SOUTH LOADS VS AREA TEMPERATURES, JULY, 1966

LOAD RANGE 1885MW TO 4368MW

TEMPERATURE RANGE 68 DEGREES TO 100 DEGREES

FIGURE 5

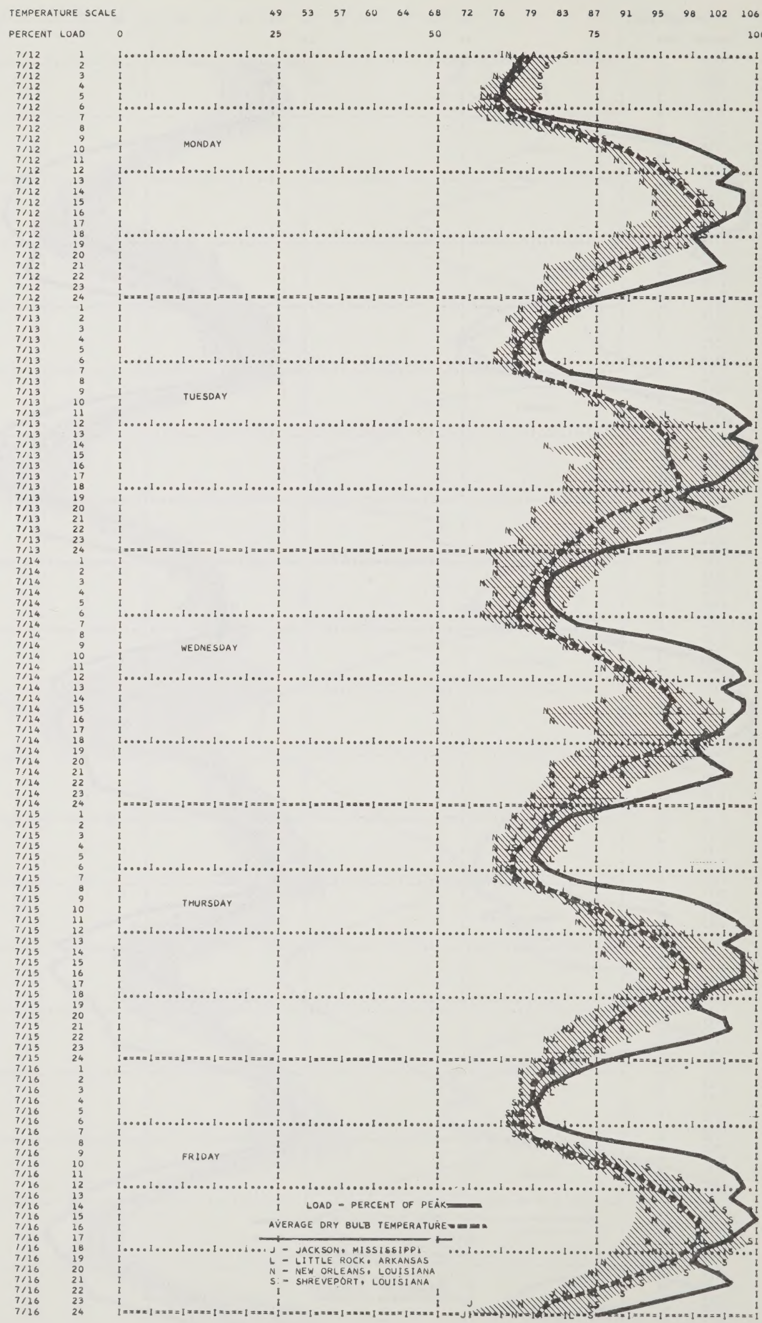


MIDDLE SOUTH LOADS VS AREA TEMPERATURES, JULY, 1954

LOAD RANGE 861MW TO 1597MW

TEMPERATURE RANGE 71 DEGREES TO 106 DEGREES

FIGURE 6

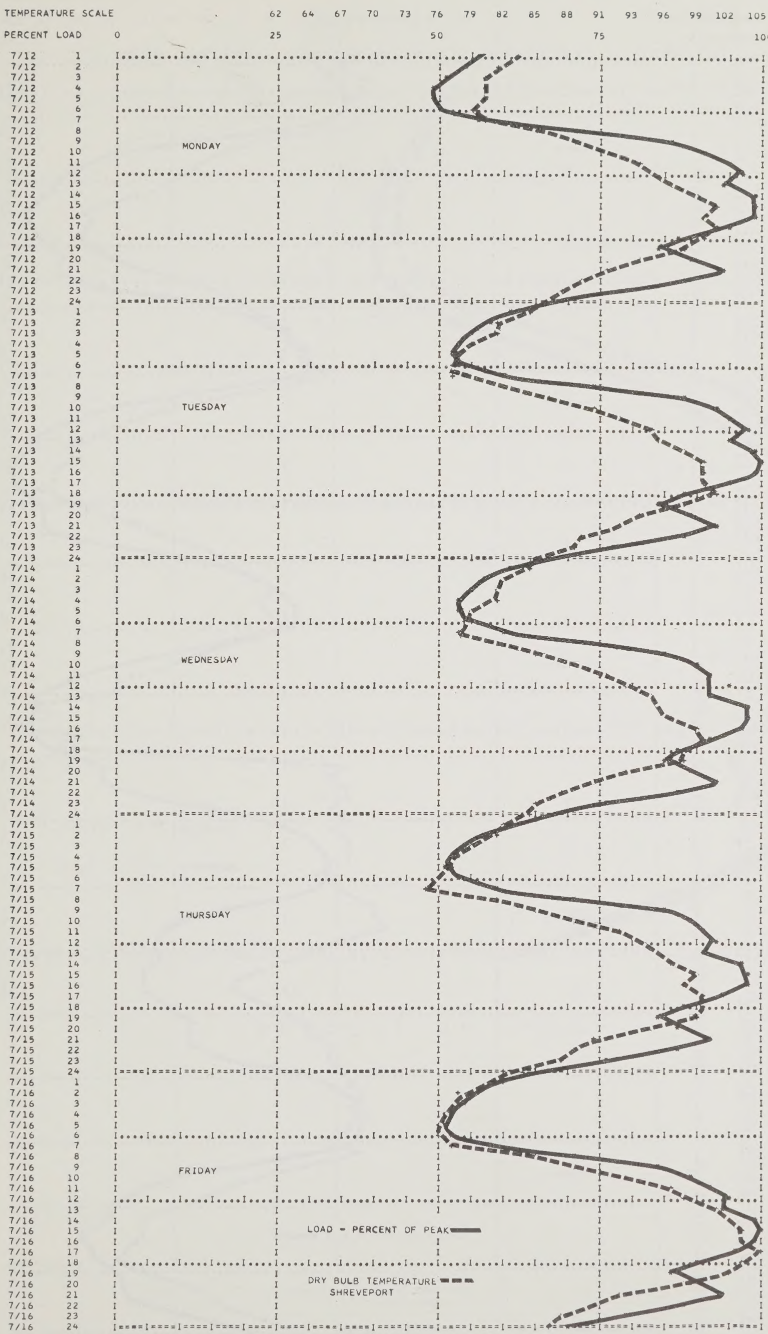


SOUTHWESTERN ELECTRIC POWER COMPANY, JULY, 1954

LOAD RANGE 133MW TO 312MW

TEMPERATURE RANGE 72 DEGREES TO 105 DEGREES

FIGURE 7



SOUTHWESTERN ELECTRIC POWER COMPANY, JULY, 1966

LOAD RANGE 329MW TO 940MW

TEMPERATURE RANGE 71 DEGREES TO 100 DEGREES

FIGURE 8

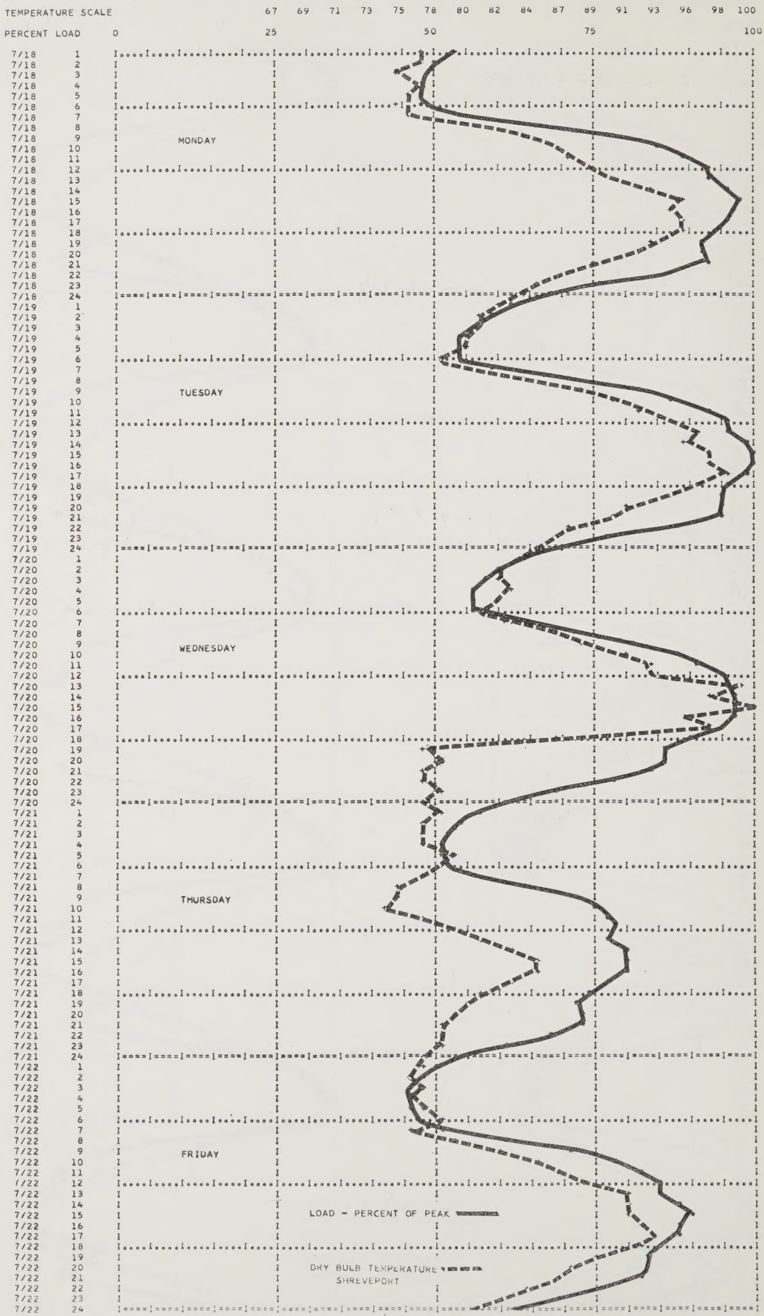


FIGURE 9

SOUTHWEST POWER POOL AVERAGE HOURLY LOADS

JULY, 1966

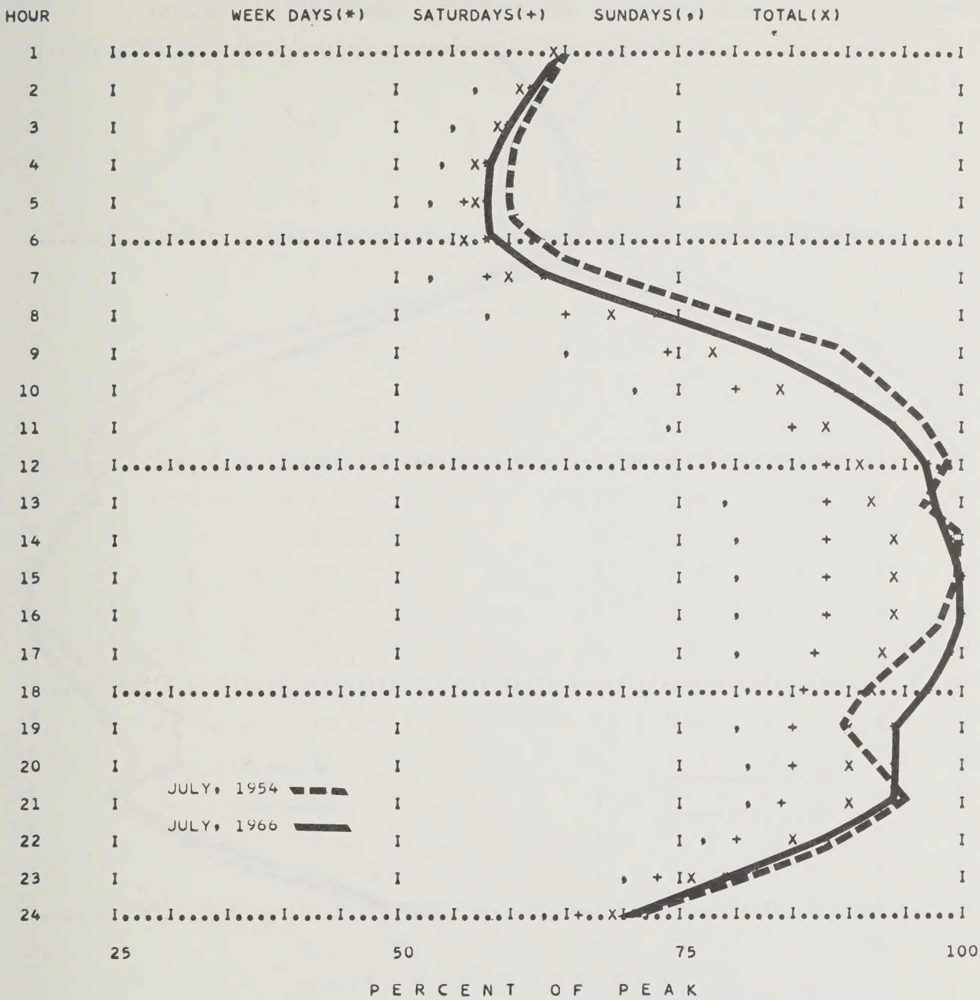


FIGURE 10

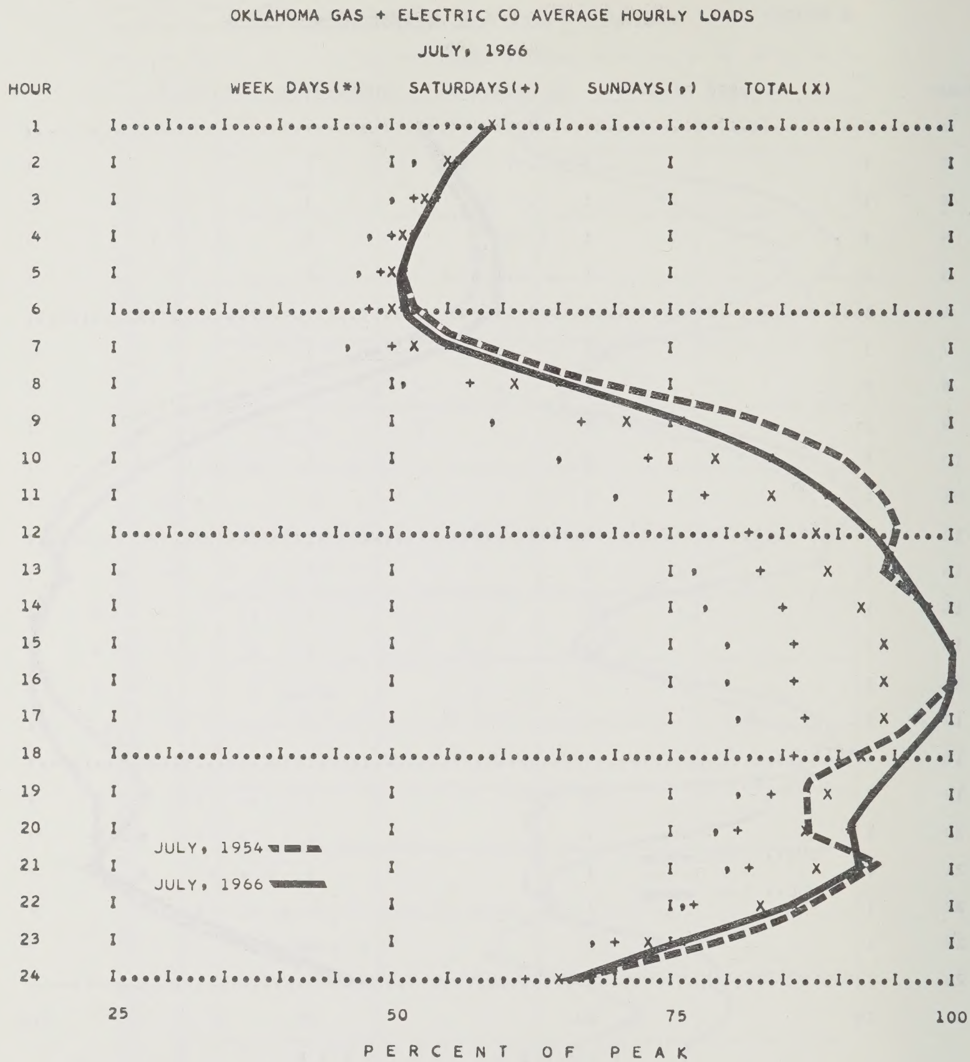

OKLAHOMA GAS + ELECTRIC CO AVERAGE HOURLY LOADS
JULY, 1966
HOUR
WEEK DAYS(*)
SATURDAYS(+)
SUNDAYS(,)
TOTAL(X)
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
JULY, 1954
JULY, 1966
25
50
75
100
PERCENT OF PEAK

FIGURE II

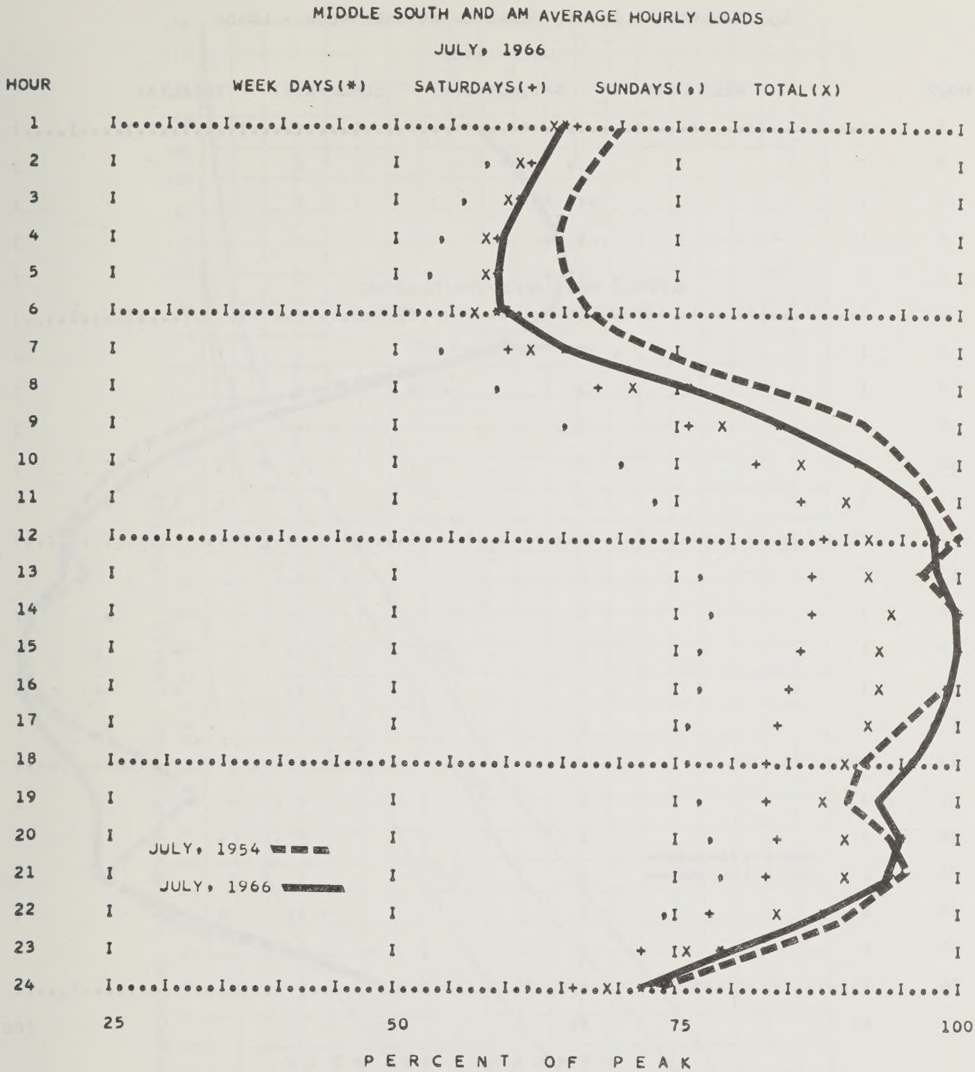

MIDDLE SOUTH AND AM AVERAGE HOURLY LOADS
JULY, 1966
HOUR
WEEK DAYS(*)
SATURDAYS(+)
SUNDAYS(,)
TOTAL(X)
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
JULY, 1954
JULY, 1966
25
50
75
100
PERCENT OF PEAK

FIGURE 12

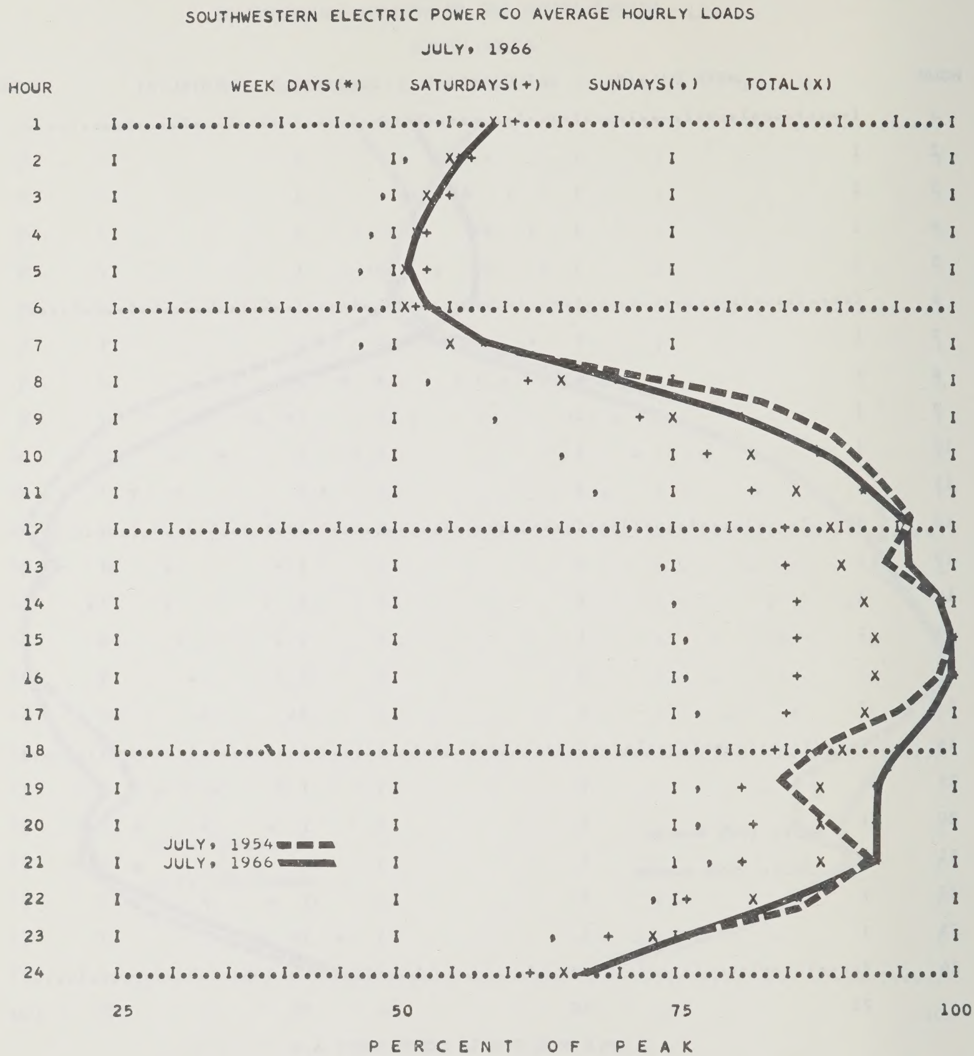
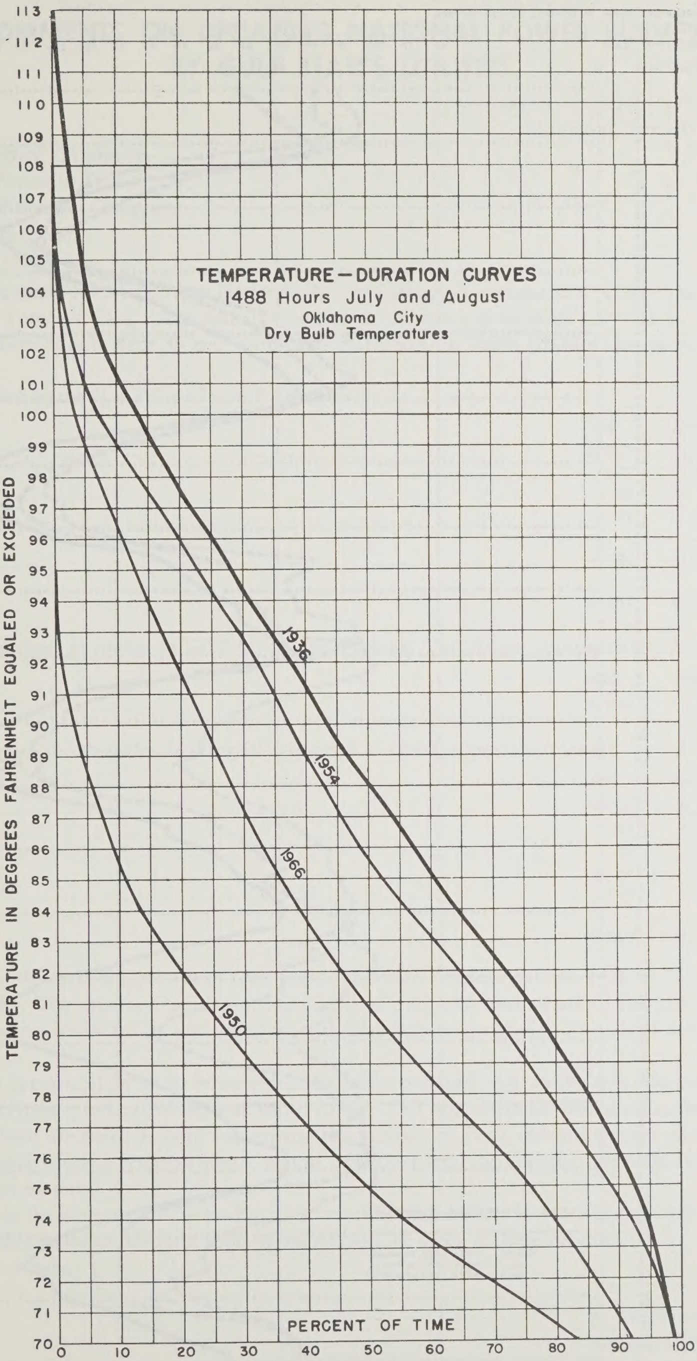

SOUTHWESTERN ELECTRIC POWER CO AVERAGE HOURLY LOADS
JULY, 1966
HOUR
WEEK DAYS(*)
SATURDAYS(+)
SUNDAYS(,)
TOTAL(X)
JULY, 1954
JULY, 1966
25
50
75
100
PERCENT OF PEAK

FIGURE 13


TEMPERATURE—DURATION CURVES
1488 Hours July and August
Oklahoma City
Dry Bulb Temperatures
TEMPERATURE IN DEGREES FAHRENHEIT EQUALED OR EXCEEDED
PERCENT OF TIME
1936
1954
1966
1950
113
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106
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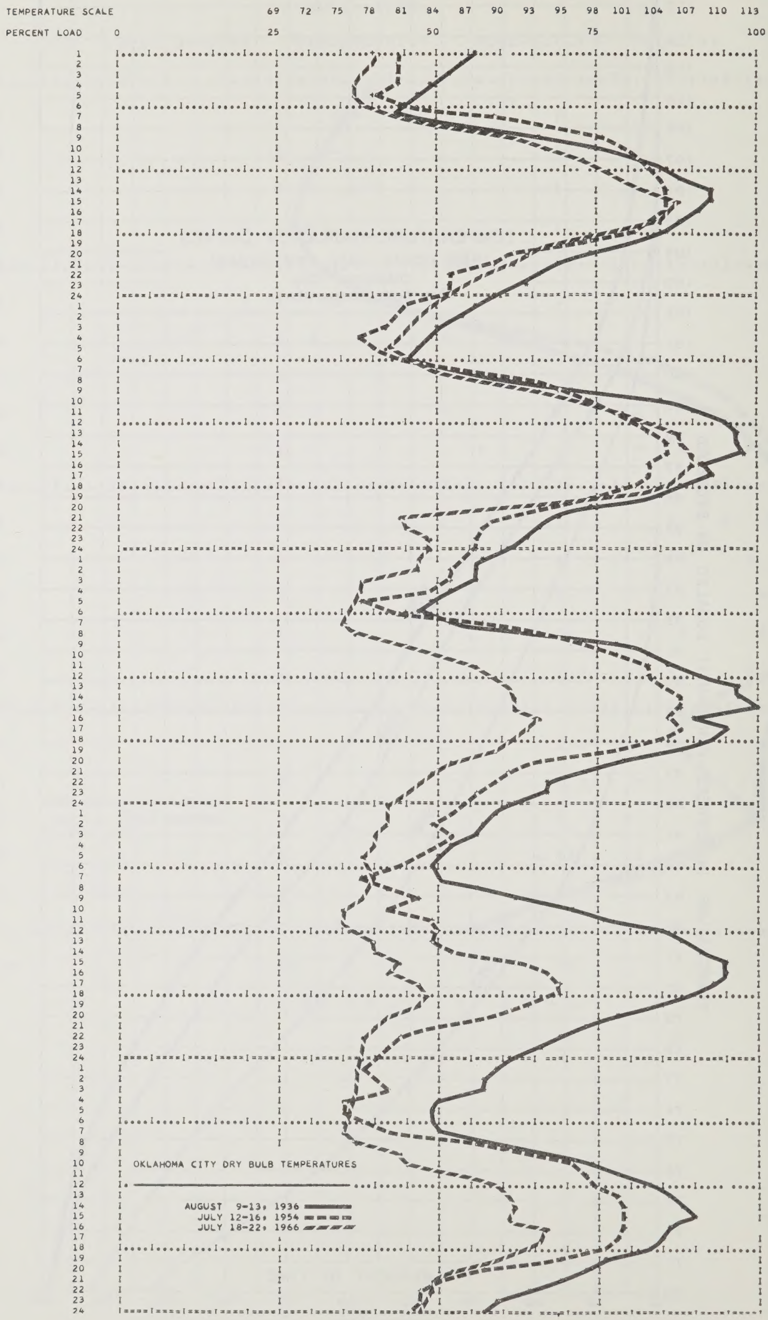
98
97
96
95
94
93
92
91
90
89
88
87
86
85
84
83
82
81
80
79
78
77
76
75
74
73
72
71
70
0
10
20
30
40
50
60
70
80
90
100

OKLA G & E CO MAX TEMPERATURES, 1936, 1954 AND 1936

FIGURE 14

TEMPERATURE RANGE 75 DEGREES TO 113 DEGREES



APPENDIX C

COMMENTS ON UPDATING NATIONAL POWER SURVEY BY GULF STATES UTILITIES

GULF STATES UTILITIES COMPANY,
Beaumont, Tex., *May 29, 1968.*

Mr. C. W. ANTHONY, *Chairman,*
SCRAC Load Forecast Task Force,
Oklahoma Gas & Electric Company,
321 North Harvey Street,
Oklahoma City, Okla.

DEAR CLARENCE: Re: Updating National Power Survey. A comparison of the load estimates of SCRAC's Load Forecast Task Force and the generation estimates of SCRAC's G and T Task Force, as they apply to Power Supply Area 35 and more particularly to Gulf States Utilities Company, indicate wide discrepancies.

Data compiled by the G & T Task Force follows:

	1970	*1980*	*1990*
Load:			
GSU	3, 267	9, 523	28, 003
CLECO	642	1, 760	4, 300
Lafayette	82	362	1, 004
Alexandria	91	222	542
PSA 35	4, 082	11, 867	33, 879
Capacity:			
PSA 35	4, 557	13, 159	38, 893

The load forecast compiled by SCRAC's Load Forecast Task Force approximately 2 years ago was:

	1970	*1980*	*1990*
PSA 35	4, 240	11, 240	24, 250

A breakdown of the above loads, using 1970 forecast as a base, appears as follows:

	1970	*1980*	*1990*
GSU	3, 267	8, 661	18, 687
CLECO	642	1, 700	3, 670
Lafayette	82	217	469
Alexandria	91	241	520
Others	158	421	904
Total	4, 240	11, 240	24, 250

For the past 34 years the growth of Gulf States Utilities Company has averaged 11.4% per year compounded annually. The attached tabulation indicates this trend. We cannot afford the luxury of reducing this trend in the foreseeable future and we agree with the load and generation forecast of the G and T Task Force.

The largest accumulation of oil refineries in the world presently exist in the area comprising Houston, Beaumont, Port Arthur, Lake Charles, and Baton Rouge. The petrochemical industries in these areas run a close second. There are many reasons influencing the location of these industries, some of which include relatively inexpensive ocean transportation, almost unlimited land availability, adequate fresh water, and abundance of raw material.

We object to the decrease in the load growth trend during the last 10 years of this survey period, as it applies to PSA 35, and we recommend appropriate revisions be made in these forecasts.

Yours very truly,

/S/ Bob
R. W. SHERWOOD,
Senior Vice President.

356-240 O—70——9

Gulf States Utilities Company Load and Capability Estimate System Yearly 60 Minute Peaks, 1933 Through 1967—Actual; 1968 Through 1973—Estimated

Year	Actual 60 minute megawatt peak	Year	Estimated 60 minute megawatt peak
1933	60	1968	2, 580
1934	66	1969	2, 935
1935	67	1970	3, 267
1936	78	1971	3, 597
1937	97	1972	4, 008
1938	100	1973	4, 466
1939	117		
1940	121		
1941	139		
1942	146		
1943	199		
1944	218		
1945	223		
1946	205		
1947	265		
1948	292		
1949	327		
1950	389		
1951	440		
1952	476		
1953	492		
1954	540		
1955	604		
1956	668		
1957	777		
1958	873		
1959	1, 041		
1960	1, 109		
1961	1, 211		
1962	1, 420		
1963	1, 531		
1964	1, 712		
1965	1, 832		
1966	2, 049		
1967	2, 300		

APPENDIX D

SOUTH CENTRAL REGIONAL ADVISORY COMMITTEE TASK FORCE ON COORDINATED PLANNING AND DEVELOPMENT HYDRO UTILIZATION SUBCOMMITTEE

By Bill C. Hulsey, Southwest Power Pool; J. R. Johnson, Federal Power Commission; Walter M. Bowers, Chairman, Southwestern Power Administration

The Task Force on Coordinated Planning and Development appointed a subcommittee to consider the aspect of the utilization of hydroelectric power (both conventional and pumped storage) on the projected 1980 and 1990 loads. The purpose of the study was to determine if existing and potential hydroelectric peaking capacity would have sufficient energy available during heat storms and drouth conditions to be usable on the South Central Region's estimated 1980 and 1990 peak loads. In order to accomplish this assignment, the subcommittee assumed that certain potential hydroelectric projects (both conventional and pumped storage) would be available to help meet total load requirements by 1980 and 1990 (See Exhibit A). The use of these potential projects in this hydro-utilization study should not be construed as a recommendation by the subcommittee that any of the potential projects should be constructed.

As demonstrated on Charts A, B, C, and D (Load Duration and Load Distribution Charts) attached hereto, the hydroelectric resources set forth in Exhibit A and summarized on Table I, totalling 5,540 mw in 1980 and 8,460 mw in 1990 can be utilized satisfactorily on the 1980 and 1990 loads. Table II depicts the estimated capacity load-resource relationship for 1980 and 1990. The total hydroelectric resource capacity in 1980 and 1990 is approximately 5.3 percent and 4.2 percent of the total 1980 and 1990 capacity requirements respectively.

In order to accomplish this assignment, the subcommittee used the load forecast and load shape adjustments for heat storm conditions recommended by the South Central Regional Advisory Committee (SCRAC) Load Forecast Task Force.[1] The hydroelectric resources considered were those listed in Federal Power Commission's (FPC) preliminary report dated February 1968 entitled Conventional and Pumped Storage Hydroelectric Resources.

Recognizing that not all of the hydroelectric resource projects listed by FPC will be feasible, the subcommittee selected certain projects which it considered might be available in 1980 and 1990.

TABLE I

Hydroelectric resources	Dependable capacity				
	Existing and under construction (mw)	Project additions to 1980 (mw)	Subtotal (mw)	Project additions to 1990 (mw)	Total (mw)
Conventional	2, 670	290	2, 960	940	3, 900
Pumped Storage	520	2, 060	2, 580	1, 980	4, 560
Total	3, 190	2, 350	5, 540	2, 920	8, 460

[1] Report on Temperature-Load Characteristics of the Southwest Power Pool dated Oct. 1967 prepared by O.G.&E. Co.

TABLE II

Load:	1980 (mw)		1990 (mw)	
Peak Annual Load	90, 980		181, 810	
Reserve Required [1]	13, 650		21, 820	
Total Capacity Requirements	104, 630		203, 630	
	1980		*1990*	
Resources:	(mw)	(%)	(mw)	(%)
Pumped Storage Hydro	2, 580	2. 5	4, 560	2. 2
Conventional Hydro [2]	2, 960	2. 8	3, 900	1. 9
Diversity Exchange	1, 500	1. 4	1, 500	0. 7
Other Plants [3]	62, 590	59. 8	123, 670	60. 8
Base Load Plants [4]	35, 000	33. 5	70, 000	34. 4
Total Resource	104, 630	100. 0	203, 630	100. 0

[1] 15% in 1980 and 12% in 1990.
[2] Dependable Capacity.
[3] Gas Turbine, Peaking Thermal, Diesel, and other Thermal Units.
[4] Conventional Thermal and Nuclear Units.

The projects existing and under construction, together with those selected, are listed on Exhibit A. It is recognized that some of the projects listed may never be built, while others may be built that are not listed. With this in mind, it is important to consider this potential as an amount of capacity and energy as summarized in Table I. The dependable capacity is considered as that available at the end of September during the minimum energy year. The total primary energy available from the projects, as accepted by the subcommittee, is the total energy estimated to be available during the minimum energy year (see Exhibit A) reduced by 15 percent to allow for the difference between the theoretical potential indicated in hydraulic studies and the amount that is obtained in actual operation.

This adjustment factor, as developed by hydraulic engineers of the Southwestern Power Administration, is based upon experienced system operation and is considered to be applicable to the total minimum energy, but not necessarily applicable to any particular project individually. Streamflows used in the computation of primary and average annual energy of the various projects are used as they occurred during the historical period with no attempt having been made to reflect changes in basin water resources development, land use and treatment, and depletion for other uses. Also many of the energy computations are based on reservoir routings on monthly basis which invariably produce a higher potential energy value than weekly or daily routings. The adjustment factor, reflecting experienced changes in primary and average annual energy in this area, is intended to correct these deficiencies in data. Further studies may indicate a need for a greater corrective factor.

The distribution of minimum year energy for conventional projects was established at 60 percent of the annual energy during the 4 peak months of June, July, August, and September with a monthly distribution in 1980 and 1990 as follows:

TABLE III

Monthly Energy Distribution

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
5%	5%	5%	5%	5%	10%	20%	20%	10%	5%	5%	5%

The 5-percent minimum monthly generation is considered essential to provide for generation requirements at run-of-the-river projects and for downstream water requirements such as fish and wildlife, pollution abatement, etc.

The pumped storage projects are expected to operate only during the peak months when needed to carry the load and will be available at other times for reserve.

The pumped storage projects assumed to be in service in 1980 and 1990 were estimated to operate during the 4 peak months on a weekly cycle of generation and pumping. The maximum daily generation was assumed to be equivalent to approximately 9 hours of continuous full load generation. Change-over time from one mode of operation to another—i.e., from generating to pumping or from pumping to generating—was assumed to be one hour. The weekly load shapes designated Charts C and D show that 2,580 mw and 4,560 mw of pumped storage capacity could be operated in the peak of the load for 5 days a week during the weeks of maximum demand in 1980 and 1990, respectively, with sufficient pumping time during the off-peak hours to sustain a weekly cycle operation. Each system must determine whether or not it can economically utilize the proposed pumped storage capacity.

In 1980 it was found that additional pumping capability would be needed if the pumping period were limited to 11:00 p.m. to 8:00 a.m. with a forebay storage of 16 hours. This problem was not experienced on the 1990 load. The pumping requirements shown on Chart C (1980 daily distribution curves) maintained these limits, but assumed the pump would be rated 25 percent greater than the generator in project design. The choice between greater pumping capability and increasing the forebay storage would be a matter of economics. In the event the project were placed higher on the load or a greater portion of the project assigned to reserve, as could be expected in system operation, such increase in pumping capability or forebay storage would not be needed.

While this subcommittee is interested primarily in the application of the hydroelectric resources to the load, other aspects of the load were necessarily considered. These other considerations include:

(1) The assumption that all loads and resources within the South Central Region will be fully coordinated by 1980.

(2) Interconnections with other regions such as Tennessee Valley Authority (TVA) and Missouri River Basin (MRB) permit the utilization of load diversity to supplement regional resources. While greater amounts of diversity are expected to be available, 1,500 mw is assumed in this report to be available from TVA during the summer peak months of 1980 and 1990 with an equal amount being returned during the winter peak months. Electrical and hydraulic diversity exist between MRB and FPC Area K, but has not been fully evaluated and is therefore not included as a resource in this report.

(3) Reserve requirements. The subcommittee is aware that any estimate of probable reserve requirements in 1980 and 1990 will be subject to question. For this reason an attempt was made to determine the existing reserve policy for a number of the larger groups. Opinions as to future trends were solicited.

Of the groups surveyed, all follow the Southwest Regional Group recommendation of a minimum of 12 percent of the peak load estimate with the exception of the Middle South System which has adopted 16 percent.

As concerns long-range estimates, several individual systems are known to feel the reserve requirements will increase to about 16 percent. However, a long-range study prepared for the MO–KAN Pool suggests that 12 percent will continue to be adequate.

As the trend to larger units (and more critical steam conditions) continues, the subcommittee feels that a trend to higher reserves by 1980 is inevitable. We suggest 15 percent would be appropriate for 1980.

From 1980–1990, as experience is gained with large units, it is felt some standardization may be manifested. This would tend to eventually reduce the reserve requirements. The subcommittee feels also that if closer coordination could be brought about and some method devised to share reserves that the area-wide requirements could be reduced. We feel the requirements by 1990 will be reduced (again) to 12 percent.

Operating recommendations of the Southwest Regional Group state that each control area shall maintain a ready reserve of not less than 6 percent of the area's predicted annual peak load with no less than 3 percent of such predicted annual peak load maintained for spinning reserve. It is with respect to spinning reserve that hydro units take on added significance. Operating Guide No. 10 of the North American Power Systems Interconnection Committee states that in the main, equivalent spinning reserve capacity may include instantaneous interruptible load, instantaneous curtailment of pumping load on pumped hydro units, condensing hydro units and similar capacity whether within the area or in neighboring areas.

Because of the reliability and quick response associated with hydroelectric resources, it is considered reasonable to hold a larger percentage of the hydro available for ready reserve. In this resource utilization study, while recognizing that 100 percent of the dependable hydro capacity can be used on the load with the available energy, the subcommittee has accepted 25 percent of the dependable hydro capacity as a reasonably conservative amount of the dependable hydro capacity to be used for reserve, with 75 percent of the dependable hydro capacity placed on the load. In this study, the 25 percent of the dependable hydro capacity that is held for reserve is equal to less than one-half of the region's spinning reserve requirements.

Recognizing the need to use gas turbine and peaking thermal plants a minimum number of hours because of their high energy cost, the subcommittee considered it appropriate to assign these resources to the peak 5 percent of the load. All hydroelectric resources (conventional and/or pumped storage) are therefore placed on the load curve below 95 percent of the monthly peak.

As shown on Charts A, B, C, and D, these hydroelectric resources will not provide all the peaking power needed by the system. In other than the minimum water year conditions the hydroelectric resources will operate at a higher plant factor.

In conclusion, the subcommittee observes that the conventional and pumped storage hydroelectric capacity expected to be available in 1980 and 1990, as set forth herein, can be utilized satisfactorily on the load.

EXHIBIT A
HYDRO RESOURCES

	Capacity[1] (MW)	Energy: Minimum year[2] (KMWH)	Energy: Average annual[3] (KMWH)
I. CONVENTIONAL HYDRO 1980			
A. Existing and Under Construction:			
Beaver	112	85	172
Table Rock	200	272	495
Ozark Beach[4]	16	61	94
Bull Shoals	340	394	785
Norfork	70	105	196
Greers Ferry	93	110	101
Denison	70	109	247
Broken Bow	86	72	139
Blakely Mountain	75	90	156
Carpenter[4]	56	63	103
Remmel[4]	10	37	50
DeGray[5]	68	60	91
Narrows	21	14	29
Keystone	72	59	228
Pensacola	86	88	330
Markham Ferry[4]	108	50	180
Fort Gibson[4]	45	61	191
Webbers Falls[4]	66	54	213
Tenkiller Ferry	34	53	114
Eufaula	90	180	317
Robert S. Kerr[4]	110	184	459
Ozark[4]	100	154	429
Dardanelle[4]	124	275	613
Toledo Bend	80	108	230
Sam Rayburn	49	49	117
Possum Kingdom	22	41	82
Whitney	28	40	82
Buchanan	34	59	100
Inks[4]	12	22	46
Granite Shoals[4]	45	37	86
Marble Falls[4]	30	21	56
Stockton	44	....	55
Mansfield	68	91	200
Austin[4]	14	31	70
Falcon	32	41	102
Kaysinger Bluff[5]	160	144	283
Total	2, 670	3, 314	7, 251
15% energy depletion adjustment[6]		−497	....
Adjusted total	2, 670	2, 817	7, 251
B. Additional by 1980:			
Kaw	25	23	89
Norfork	85	−7	22
Wolf Bayou[4]	180	225	420
Total	290	241	531
15% energy depletion adjustment[6]		−36	....
Adjusted total	290	205	531

See footnotes at end of table.

HYDRO RESOURCES—Continued

	Capacity [1] (MW)	Energy: Minimum year [2] (KMWH)	Energy: Average annual [3] (KMWH)
II. PUMPED STORAGE 1980:			
A. Existing and Under Construction:			
Salina	520		
B. Additional By 1980:			
Optimus	500		
Tuskahoma	1, 000		
Petit Jean	561		
Total	2, 061		
III. ADDITIONAL RESOURCE BY 1990:			
A. Conventional:			
Grandview	18	8	34
Galena	43	19	60
Bell Foley	24	11	26
Buck Creek	12	10	12
Hugo Dam	50	55	71
Pine Creek	86	38	58
Lukfata	35	33	44
Tuskahoma	19	16	28
Hartley	14	12	17
Sherwood	103	64	98
Gainesville	50	54	82
Dougherty	25	22	63
Durwood	20	18	48
Denison	52	0	35
Stateline	134	59	93
Carthage	16	8	24
Bon Wier	20	4	85
Gainesville (Area J)	50	54	82
Denison (Area J)	52	0	35
Morris Sheppard	11	0	11
Choke Canyon	12	5	5
Upper Antlers	90	85	123
Total	936	575	1, 134
15% Energy depletion adjustment [6]		−86	
Adjusted total	936	489	1, 134
B. Pumped Storage:			
Sherwood	500		
Boktukola	1, 000		
Mulladay	485		
Total	1, 985		

[1] Dependable (End of September) from FPC pooling report on conventional and pumped storage hydroelectric resources dated February 1968. On projects where dependable capacity was not reported, the installed capacity was used.

[2] Critical period energy from FPC pooling report on conventional and pumped storage hydroelectric resources dated February 1968.

[3] Average annual generation from FPC pooling report on conventional and pumped storage hydroelectric resources dated February 1968.

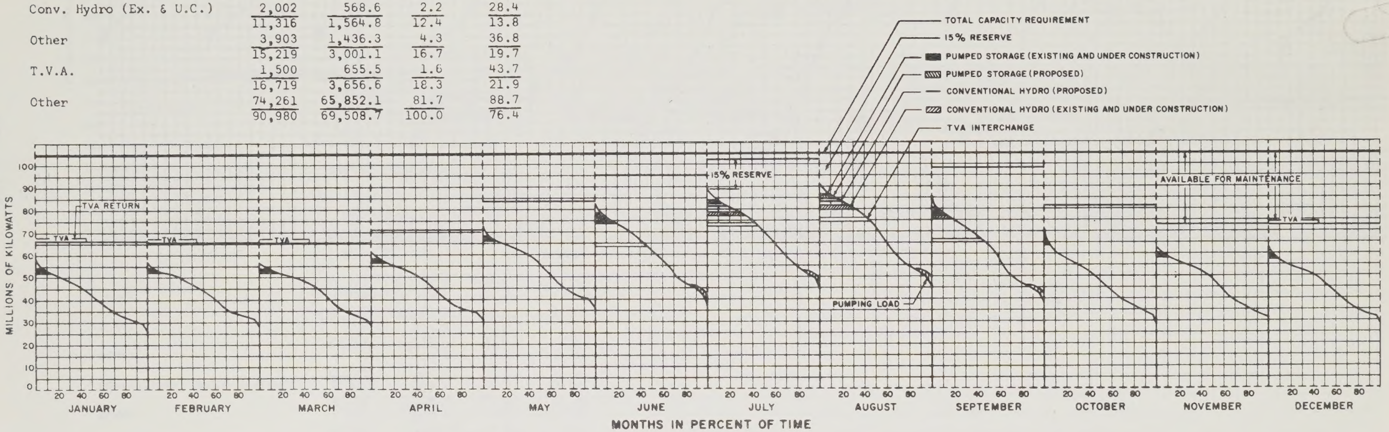
[4] Run-of-river installations.

[5] Conventional Hydro with Reversible Turbines.

[6] Minimum year energy as listed herein has already been adjusted for hydraulic and unit efficiencies and this "depletion" adjustment of 15% is in addition thereto.

POSSIBLE AUGUST LOADING

	Peak (mw)	Energy (mw-Mo.)	Peak (%)	Required Load Factor (%)
5%	4,549	191.0	5.0	4.2
Pumped Storage (Ex. & U.C.)	390	35.5	0.4	9.1
	4,939	226.5	5.4	4.6
Pumped Storage (Proposed)	1,546	194.8	1.7	12.6
	6,485	421.3	7.1	6.5
Other	899	151.9	1.0	16.9
	7,384	573.2	8.1	7.8
Conv. Hydro (Proposed)	218	41.2	0.2	18.9
	7,602	614.4	8.3	8.1
Other	1,712	381.8	1.9	22.3
	9,314	996.2	10.2	10.7
Conv. Hydro (Ex. & U.C.)	2,002	568.6	2.2	28.4
	11,316	1,564.8	12.4	13.8
Other	3,903	1,436.3	4.3	36.8
	15,219	3,001.1	16.7	19.7
T.V.A.	1,500	655.5	1.6	43.7
	16,719	3,656.6	18.3	21.9
Other	74,261	65,852.1	81.7	88.7
	90,980	69,508.7	100.0	76.4

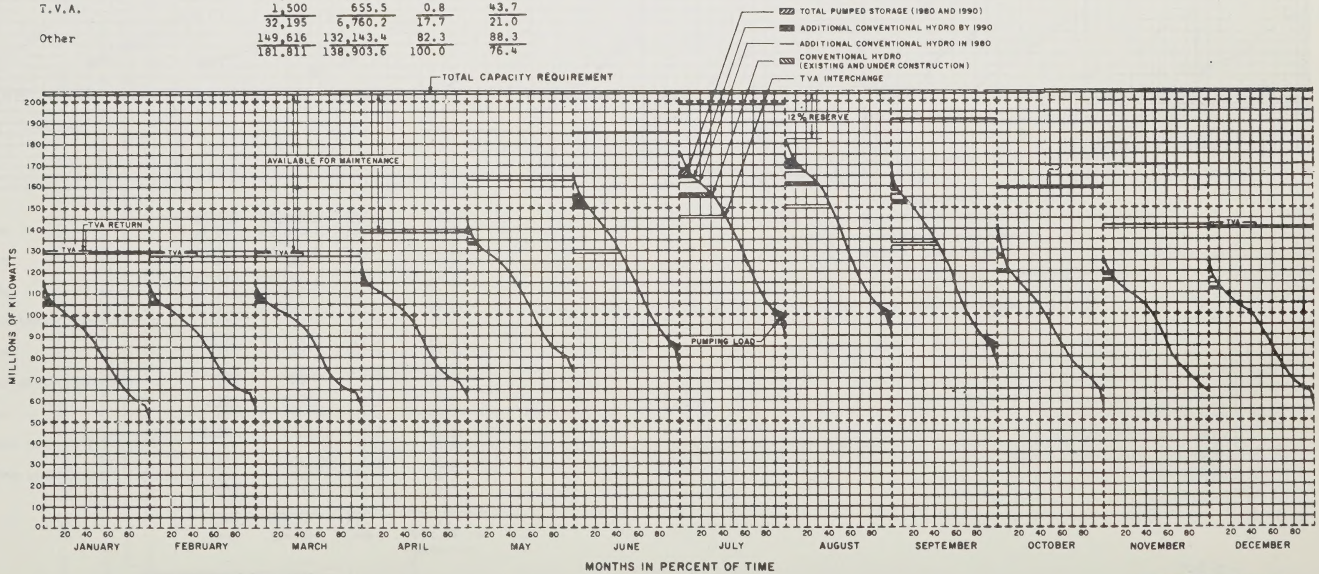


LOAD DURATION CURVES
SOUTH CENTRAL REGION
ADVERSE YEAR 1980

CHART A

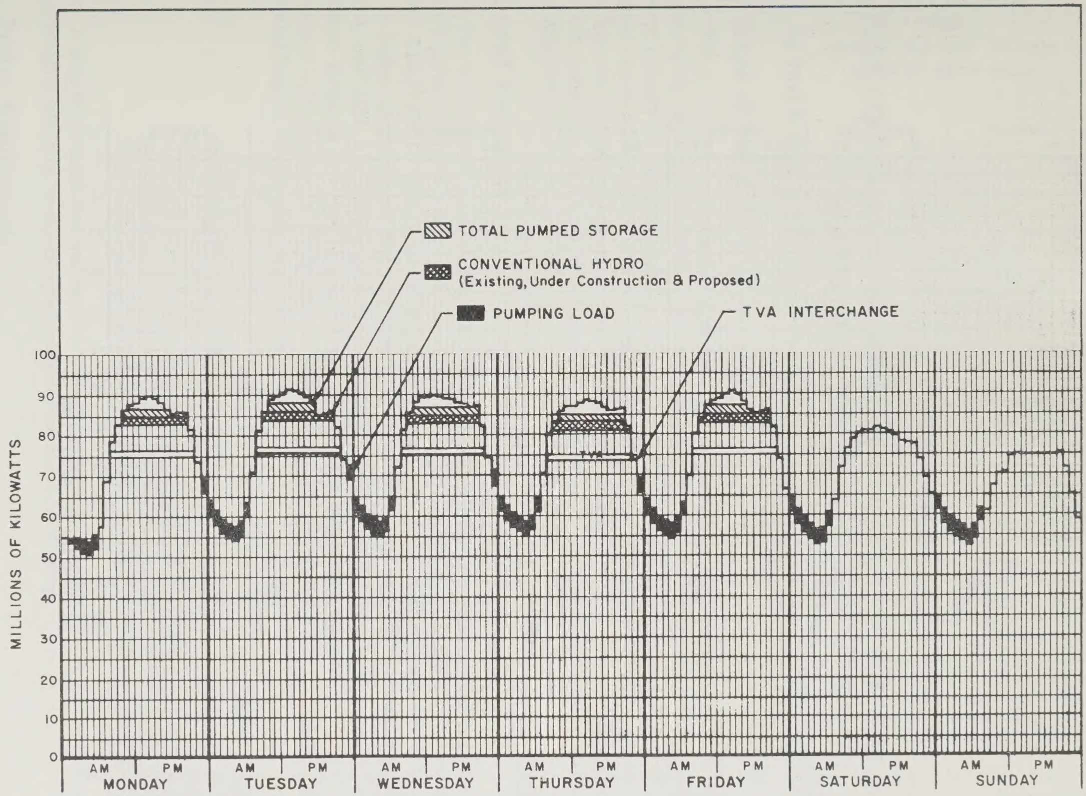
POSSIBLE AUGUST LOADING

	Peak (mw)	Energy (mw-Mo.)	Peak (%)	Required Load Factor (%)
5%	9,090	381.8	5.0	4.2
Pumped Storage	3,424	390.3	1.9	11.4
	12,514	772.1	6.9	6.2
Additional Conv. Hydro 1990	702	106.0	0.4	15.1
	13,216	878.1	7.3	6.6
Other	1,627	279.8	0.9	17.2
	14,843	1,157.9	8.2	7.8
Additional Conv. Hydro 1980	218	41.2	0.1	18.9
	15,061	1,199.1	8.3	8.0
Other	4,495	1,029.4	2.5	22.9
	19,556	2,228.5	10.8	11.4
Conventional Hydro (Ex.&U.C.)	2,002	568.6	1.1	28.4
	21,558	2,797.1	11.9	13.0
Other	9,137	3,307.6	5.0	36.2
	30,695	6,104.7	16.9	19.9
T.V.A.	1,500	655.5	0.8	43.7
	32,195	6,760.2	17.7	21.0
Other	149,616	132,143.4	82.3	88.3
	181,811	138,903.6	100.0	76.4



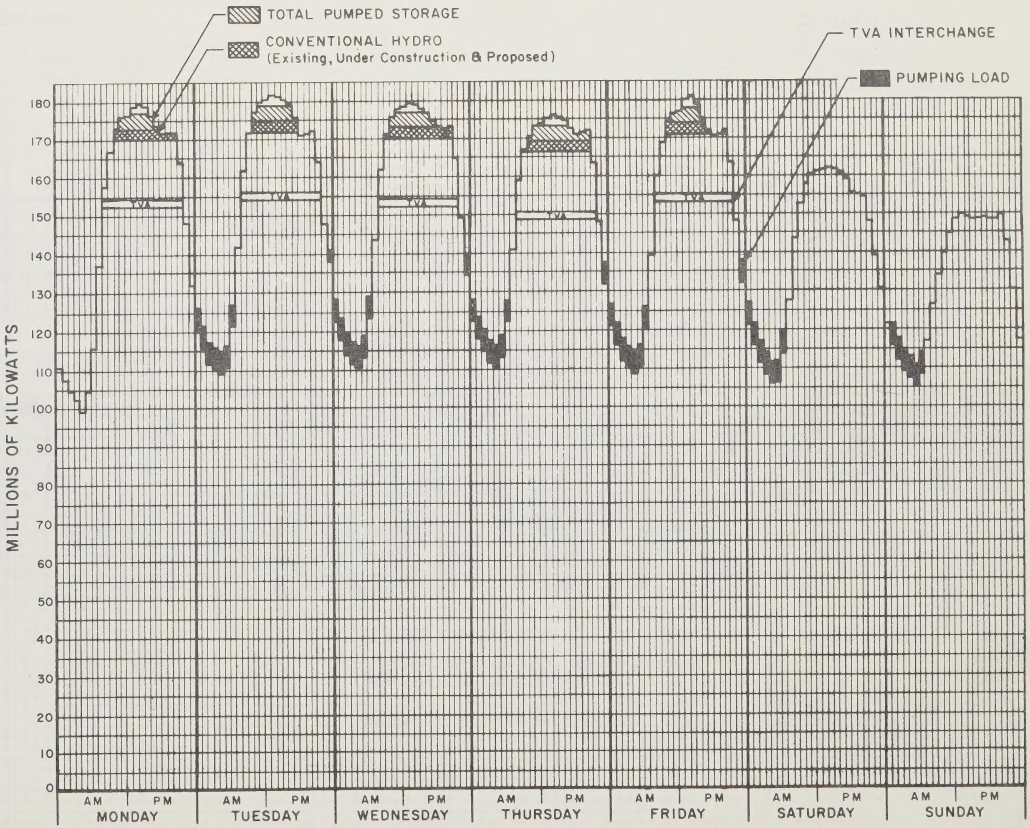
LOAD DURATION CURVES
SOUTH CENTRAL REGION
ADVERSE YEAR 1990

CHART B



TYPICAL PEAK WEEK
SOUTH CENTRAL REGION
1980

CHART C



TYPICAL PEAK WEEK
SOUTH CENTRAL REGION
1990

CHART D

APPENDIX E

FUTURE COOLING WATER NEEDS AND RESOURCES FOR THERMAL-ELECTRIC GENERATION IN THE SOUTH CENTRAL REGION

By Paul E. McKee, Fort Worth Regional Office, Federal Power Commission, February 1968

A. Scope of the Report

This report is prepared as reference material for the Generation-Transmission Task Force in developing a generating capacity extension program. It summarizes the estimated future water needs of the electric power industry in the South Central Region and points out possible adverse effects on the public water supply attributable to electric power generation. It represents a collection of known factors which supply the base for future projections as noted herein. The preliminary data on water requirements for thermal electric generation as presented herein were included in the first national water assessment completed by the Water Resources Council.

B. Load Projections

For a number of years the electric power industry has experienced a remarkable annual growth rate of 6 to 7 percent. This rapid growth has complicated the predictions of generation patterns beyond 1980 or 1985. The Federal Power Commission's Fort Worth Regional Office has compiled basic energy requirements in its region for the years 1950, 1955, 1960, and 1965, and projections for the years 1970, 1980, 1990, 2000, 2010, and 2020. The energy projections through 1990 are those prepared in cooperation with the South Central Regional Advisory Committee of the National Power Survey. The estimates beyond 1990 were obtained by projecting a straight line utilizing the 1985 and 1990 points. The projections for the South Central Region, for selected years are as follows:

Year	*Million kwh*
1965 (actual)	118, 641
1980	442, 630
1990	900, 380
2000	1, 421, 000
2020	2, 455, 400

It is to be realized that making estimates of energy requirements as of the year 2000 and 2020 can only be a rough guide to be reviewed periodically as new situations develop.

C. Water Requirements

Water is a factor in the production of all electric power now generated. The amount of hydroelectric power involved, particularly after 1980, will be a very minor percent of the total energy requirement in the South Central Region. Likewise, it is anticipated that generation by internal combustion engines and by gas turbines will represent an insignificant part of the total demand. These plants consume little or no water but all plants, however, do require small amounts of water for station services. Thus, the future large water requirement pertains to steam electric generating plants.

The principal use of water in steam electric generating plants is for condenser cooling purposes. Small amounts of extremely pure water are required for boiler use and larger amounts of untreated water serve for condenser cooling. The only consumptive use of the boiler circuit is the feedwater make-up required to replace water losses. Losses occur in the condenser cooling system when the condenser flows are either returned to the source bodies of water at higher temperatures or passed through a cooling tower.

The water requirement for condenser flows depends upon the type and the operating characteristics of the plant. At this time, large nuclear thermal electric plants require about 50% more condenser water for a given temperature rise than fossil-fueled thermal electric plants of equal size. It is expected that this added requirement will decrease to about 25% by 1980. Nuclear breeder reactors may be commercially available during the 1980's. They will probably produce steam at temperatures approximating those now associated with fossil-fueled boilers. It is also anticipated that further improvements will be made in the efficiencies of fossil-fueled plants.

Once-through cooling systems are normally more economical than other systems, and they are adopted where adequate supplies of cooling water are available and such use would not violate adopted water quality standards. Sources of water for once-through systems include flowing streams, lakes, reservoirs, off channel ponds, estuaries, and the ocean. Where suitable sites for ponds or reservoirs are not available and limited flows or temperature restrictions prevent use of available streams, some type of cooling device must be used. In the open cycle or "wet" systems, the cooling water is brought in direct contact with a flow of air and the heat is dissipated principally by evaporation. Such systems commonly use cooling towers with the flow of air provided by either mechanical means or natural draft. Makeup water for such systems may be obtained from surface or ground water sources and, in some cases, effluents from sewage treatment plants are used. Evaporative cooling towers require smaller amounts of water withdrawals but the consumptive use is substantially higher than for the once-through systems. Closed cycle systems using "dry" cooling towers dissipate heat to the air by conduction and convection rather than evaporation. Because of their high costs and their adverse effects on the efficiency and capability of the powerplant, such systems are not in general use.

A projection of the water requirements for the South Central Region was based on the projected requirements for four major regions which embrace essentially the SCRAC area. These are: Lower Mississippi Basin, Arkansas-White-Red Basins, Texas-Gulf Basins, and Rio Grande Basin. After projecting power generation according to type of plant, it was necessary to estimate the type of cooling likely to be used and its likely source. Then, by application of water use factors, projections of water requirements were made. The estimated actual 1965 and the projected requirements for the South Central Region are listed below:

Year	Millions of gallons per day	
	Condenser requirement	Consumptive use
1965	13,000	130
1980	49,000	380
1990	80,000	635
2000	121,800	1,000
2020	188,900	1,480

New methods of generating power, which eliminate the conventional cycle and obviate the need for cooling water, are being investigated. Some of these may be developed for commercial use before 2020. Development and adoption of technological innovations and improvements may substantially alter future cooling water requirements.

D. Water Resources

Figure 1, attached hereto, shows the average annual runoff for streams in the South Central Region. Based on the 1931–1960 period of 30 years, average annual runoff varies from less than 5 inches on the western portion to about 20 inches on the eastern portion of the Region. Average runoff for 1954, an extremely dry year, is shown on Figure 2. These figures stress the geography of the region which contributes to possible water problems. All major west-east drainage rises in, or just outside, the western part of the region which is also an area of low average rainfall. During the drouth year of 1954 the western 55 percent of the region experienced annual runoff of less than 2 inches as compared to 18 inches and above in the southeast corner. A check of gauging station records in the lower reaches of major drainage in the region indicates runoff for 1954 of an estimated 43,000 mgd, exclusive of the Mississippi River and its eastern

tributaries. This estimate takes into account all upstream diversions and storage. This can generally be classified as surplus water, other than that necessary to maintain satisfactory flow conditions, and could have been diverted to useful purposes upstream.

It is reasonable to assume that there will be no serious problem over cooling water availability in the Lower Mississippi Basin in the foreseeable future. The elimination of that basin from the total requirements would revise the estimate to the following condenser requirements (in mgd) : 1965—11,220; 1980—39,500; 2000—94,900; and 2020—139,200. It can be seen that, even in a drouth year, available surface water can make a significant contribution to the total added requirements up to the year 1980. However, beyond that year, the estimated increase in circulatory requirements dwarfs the availability of surface water under adverse conditions thus requiring multiple reuse.

An attempt was made to obtain some estimate of ground water availability for presentation on the attached Figure 3. Meager data on estimated yield were available for all States in the region except the State of Texas and have been interpreted for use on this figure. Major water bearing formations in the State of Texas have been delineated, but expected yields are not available. Reliable sources of information indicate that the potential yield of most ground water sources has declined considerably during the past 10–15 years.

E. Thermal Pollution Problems

As the amount of waste heat from steam electric powerplants discharged to water bodies has increased, concern for thermal pollution and its effects has increased. The electric power industry represents the largest single source of thermal discharge to our lakes and streams. There are a number of effects of thermal pollution which are harmful to our environment but the degree of harmfulness is not fully established in all cases. Physical, chemical, and biological properties of water are closely related to temperature and temperature data are essential for planning multiple uses of water resources. Growth of taste-and-odor-producing bacteria in lakes and impoundments may be stimulated by warm temperatures. Dense bacterial growth can add to costs of water purification treatment. Not the least important of the effects of waste heat disposal is the reduction in the utility of the water for further cooling.

Temperature affects the ability of water to sustain aquatic life. Oxygen is less soluble in warm water than in cold water, and the quantity of oxygen in solution may be further diminished as increased temperatures accelerate biological activity. Fish tolerance of lower oxygen levels and pollutant concentrations varies by species.

Under the provisions of the Water Quality Act of 1965, all 50 States have prepared water quality standards for interstate streams and coastal waters and have submitted them to the Secretary of the Interior for approval. The temperature criteria in such standards have been approved by the Secretary for all States in the South Central Region except Mississippi and Kansas. For the five States in the region with approved temperature criteria, the general provisions, with exceptions for certain streams, allow a maximum temperature rise of 5° F and maximum temperatures as follows: Missouri, 90°; Oklahoma, 93°; Arkansas, 95°; Texas, 96°; and Louisiana, 97°. The excepted streams generally have lower permissible maximum temperatures to protect cold water fish. Missouri standards permit no temperature rise in lakes and reservoirs. Texas standards for tidal waters permit temperature rises of 1.5° in summer and 4° in other seasons.

The approved water quality standards may be enforced by the States. They are also subject to the enforcement procedures set forth in the Federal Water Pollution Control Act. Under these procedures the enforcement is by the Secretary of the Interior, coordinating generally with the Governors of the States.

F. Conclusions

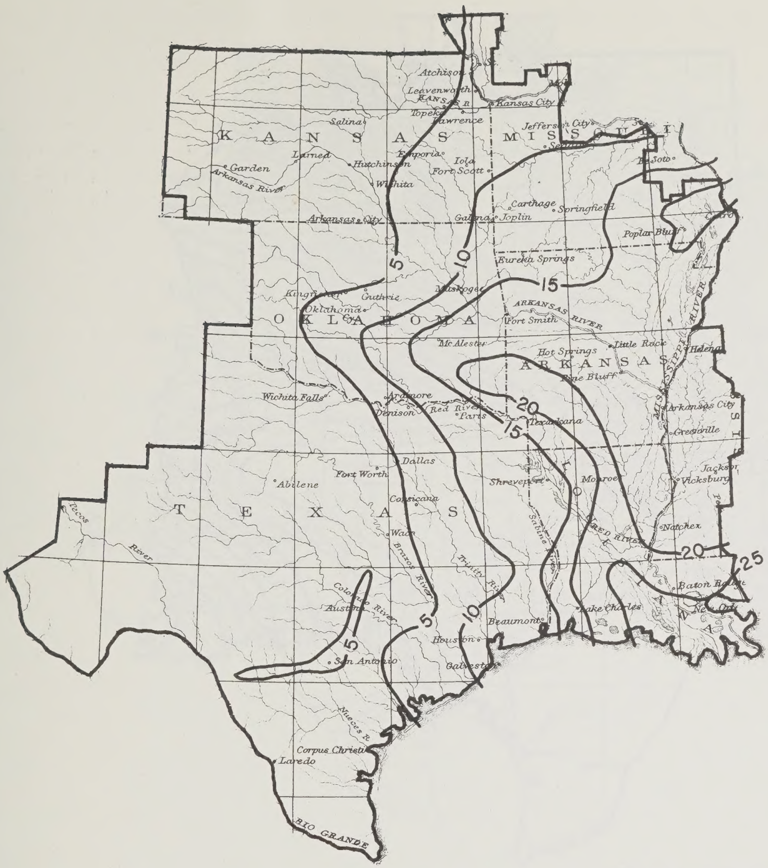
The immediate and economic development of the electric power industry is important and time is of the essence since the industry need is becoming critical. A large portion of the South Central Region is an area of short water supplies for all purposes, including industrial use. Comprehensive studies leading to plans for adequate development of the water resources for all purposes are being made in several areas, including the Sabine River Basin, the White River Basin, and the Red River Basin below Denison Dam. Other plans envision large scale interbasin diversion of water but there is no reason to anticipate concrete results from this idea before 1980.

As the amount of waste heat from steam electric powerplants discharged to water bodies has increased, concern over thermal pollution and its effect has increased. This has compounded the problem of water supply in areas with a tendency toward water shortages.

One aspect of the problem is to obtain the maximum possible use of our rivers and lakes for heat dissipation. Electric utilities obviously will continue as the largest single source of thermal discharge in the foreseeable future. The industry has long been concerned with the effects of thermal pollution and has over the years accumulated considerable data and experience on thermal discharge technology. A considerable annual operating cost penalty, transferrable in some ratio to the customer, could result for each plant if it were forced either to employ artificial cooling or to locate at some distance from its intended load center for lack of sufficient cooling water.

Industry and government together share a mutual obligation to work on the problem. Increasing responsibility for basic research on the effects of thermal discharges probably lies with the electric utility industry. There is still much to be learned with regard to the manner in which large and small, and temporary and sustained changes can affect the life cycles of aquatic plants and animals and the utility for other uses of water bodies which assimilate cooling releases. Until much needed research is completed flexibility, rather than the establishment of firm thermal discharge standards, is desirable.

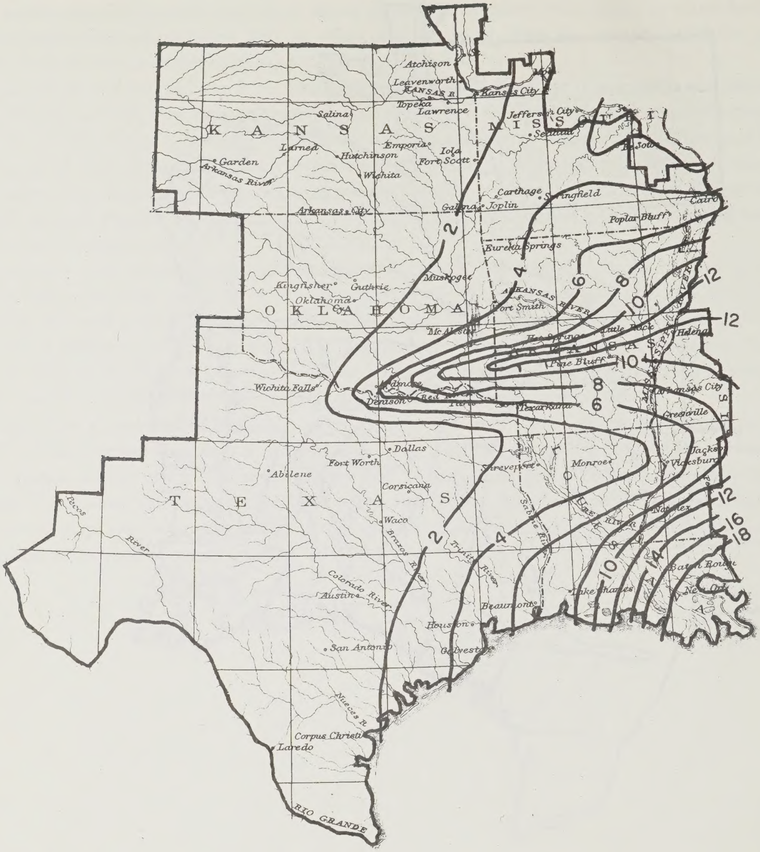
Based on knowledge of available water supply, and restrictions on the use thereof, it is inevitable that there will be a serious problem of supply, beginning particularly in the 1980–2000 period. This problem is not confined to the electric power industry and requires continued cooperative study by all water using entities. Continued development of generating techniques oriented toward conservation of water in the generation of power is an obligation of the electric power industry, just as each other user has a similar obligation in the area of conservation.



ANNUAL RUNOFF IN INCHES
1931-1960 AVERAGE
SOUTH CENTRAL REGION

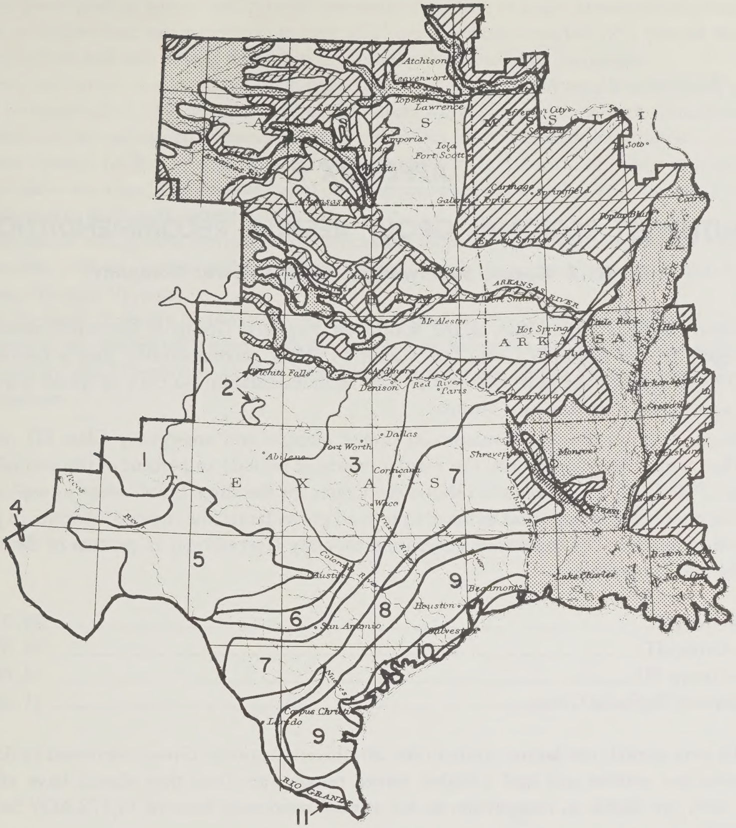
FIGURE 1

356-240 O—70——10



ANNUAL RUNOFF IN INCHES
1954
SOUTH CENTRAL REGION

FIGURE 2



Major Water Bearing Formations in Texas (Yield not available)

1. Ogallalla Formation
2. Seymour Formation
3. Trinity Sands
4. Alluvial Deposits
5. Edwards Limestone and Trinity Sands
6. Edwards Limestone
7. Carrizo-Wilcox Sands
8. Catahoula-Oakville-Lagarto Sands
9. Goliad-Willis-Lissie Sands
10. Beaumont Sands
11. Alluvium

Yield in Gallons Per Minute

- More than 500
- 50 to 500
- Less than 50

GROUND WATER RESOURCES
SOUTH CENTRAL REGION

FIGURE 3

APPENDIX F

SOUTHWEST REGIONAL GROUP RESERVE RECOMMENDATION

By W. J. Googe, Southwestern Electric Power Company

The Reserve Capacity Committee of the Southwest Regional Group of the Interconnected Systems presented a report to the Regional Group on March 14, 1968, recommending that a reserve generating capacity of 12% be used for the year 1968–1969. This recommendation—a copy of which is attached—was accepted and approved by the Regional Group.

Table No. A–1 shows the actual maximum forced outages and emergency Class III outages (those emergencies that connot be delayed until the regular overhaul period) in percent of the annual peak for the 10 year period 1958–1967. This tabulation shows the values for the three Sub-Groups as well as the Region as a whole. It is interesting to note that as the area or load grows larger the required reserve, in percentage of the total, becomes smaller. The maximum generating capacity (forced out) in percent of the total installed capacity for the last 10 years was:

Sub-Group I	24.71%
Sub-Group II	14.31%
Sub-Group III	14.69%
Southwest Regional Group	11.58%

During this 10 year period, the largest units in the Southwest Regional Group increased to 550 MW. The larger units were not mature and had a higher forced outage rate than they should have after maturity. These larger units are sizable in comparison to the annual maximum hour of 14,372 MW in 1967 for the Region as a whole.

It seems reasonable to believe that in the future years as the size of the larger units is increased, the required reserve for this size area should probably peak at 16% to 18%. This value should probably decrease after the unit size reaches the maximum that can be constructed and the ratio of the total capacity in the area to the largest size units returns to an upward trend.

SOUTHWEST REGIONAL GROUP RESERVE CAPACITY COMMITTEE

Recommendations for 1968–1969

It is the recommendation of the Reserve Capacity Committee that the Southwest Region continue to use twelve percent (12%) reserve until historical data, calculated similar to that shown on Table A–1 using only Forced Outages and Class III Emergency Scheduled Outages, proves that this value should be changed. This recommendation of 12% is based on the following:

(1) Each participating system *will* add this percentage reserve to its estimated yearly peak and will provide generating capability not smaller than the sum of the two. The variable weather condition over this large area should cause the sum of the estimated peaks based on hot summers to be larger than the sum of the actual peaks. This excess plus the excess reserve capability due to each system using a minimum of 12% reserve should readily provide for the short time peak and for reasonable errors in load forecasting.

(2) Each participating system *will* provide necessary capacity, or make arrangements with their neighbors to utilize their excess reserve, so they will have the recommended 12% reserve during all overhaul periods and also during times they are making winter sales or exchanges.

(3) When any system installs large, new type, unproven units, it *will* supply additional reserve above the recommended 12% to take care of the unknown performance of such immature units; some systems are now using 16% reserve, until the reliability of such units is determined.

(4) Those systems having a large percent of their capability in the form of hydro generation *may wish* to consider less than 12% reserve based on historical data of reliability and the size of its largest unit in relation to their peak system load.

(5) Each system *will* review its method of forecasting its yearly peak hour and be sure that it compares favorably with an exponential trend line drawn through the highest peak hours that have occurred during the past 10 years.

(6) The Reserve Capacity Committee will be continued by the Southwest Regional Group, and the systems in this Group will continue to send to the Southwest Power Pool office the same information for use by the Committee as they have done in the past, unless changes are requested by the Committee.

TABLE A-1

Maximum Forced Outages and ESO Class III Outages in Percent of Annual Max Hours, 1958–1967, Inclusive

Year and sub-group	Annual maximum MW out coincidentally (1)	Max total MW out coincidentally—last 10 yrs (2)	Annual Max hour (3)	Max MW out in % of annual Max Hr (1÷3)	Max MW out—Last 10 yrs in % of annual Max Hour (2÷3)
1958					
Sub-Group I	742	742	3, 003	24. 71	24. 71
Sub-Group II	178	178	1, 727	10. 30	10. 30
Sub-Group III	116	175	1, 779	6. 52	9. 84
SWRG	742	742	6, 407	11. 58	11. 58
1959					
Sub-Group I	616	742	3, 443	17. 89	21. 55
Sub-Group II	272	272	1, 901	14. 31	14. 31
Sub-Group III	201	201	1, 960	10. 25	10. 25
SWRG	707	742	7, 222	9. 79	10. 27
1960					
Sub-Group I	461	742	3, 682	12. 52	20. 15
Sub-Group II	280	280	2, 038	13. 74	13. 74
Sub-Group III	220	220	2, 016	10. 91	10. 91
SWRG	537	742	7, 661	7. 01	9. 69
1961					
Sub-Group I	685	742	3, 832	17. 88	19. 36
Sub-Group II	292	292	2, 155	13. 55	13. 55
Sub-Group III	181	220	2, 230	8. 12	9. 87
SWRG	742	742	7, 961	9. 32	9. 32
1962					
Sub-Group I	791	791	4, 549	17. 39	17. 39
Sub-Group II	306	306	2, 460	12. 44	12. 44
Sub-Group III	116	220	2, 395	4. 84	9. 18
SWRG	791	791	9, 343	8. 47	8. 47
1963					
Sub-Group I	835	835	5, 018	16. 63	16. 63
Sub-Group II	293	306	2, 734	10. 72	11. 20
Sub-Group III	213	220	2, 700	7. 88	8. 15
SWRG	847	847	10, 083	8. 41	8. 41
1964					
Sub-Group I	496	835	5, 637	8. 80	14. 81
Sub-Group II	356	356	3, 064	11. 62	11. 62
Sub-Group III	175	220	2, 004	5. 83	7. 32
SWRG	791	847	11, 409	6. 93	7. 42
1965					
Sub-Group I	553	835	5, 913	9. 35	14. 12
Sub-Group II	318	356	3, 193	9. 96	11. 15
Sub-Group III	209	220	2, 052	6. 85	7. 21
SWRG	564	847	12, 090	4. 67	7. 01
1966					
Sub-Group I	528	835	6, 810	7. 75	12. 26
Sub-Group II	297	356	3, 648	8. 14	9. 76
Sub-Group III	339	339	3, 577	9. 48	9. 48
SWRG	889	889	13, 796	6. 44	6. 44
1967					
Sub-Group I	1, 576	1, 576	7, 334	21. 49	21. 49
Sub-Group II	224	356	3, 748	5. 98	9. 50
Sub-Group III	511	511	3, 479	14. 69	14. 69
SWRG	1, 585	1, 585	14, 372	11. 03	11. 03

APPENDIX G

COST COMPARISON OF THERMAL GENERATION

Prepared by Fort Worth Regional Office, Federal Power Commission

The information presented in this Appendix was developed and furnished to the Task Force of General Patterns of Generation and Transmission by the Fort Worth Regional Office of the Federal Power Commission. These estimates show approximate average SCRAC regional busbar generation cost, in mills per kilowatt hour, based on current prices, projected prices in the 1975 to 1980 period, and projected prices in the 1981 to 1990 period, from two-unit plants utilizing the three major fuels:

Average SCRAC Regional Busbar Generation Cost, Mills/kwh

Period	Gas	Coal	Nuclear
Current	4. 3	5. 4	6. 2
1975–1980	4. 6	5. 3	5. 2
1981–1990	5. 0	5. 3	4. 5

These generation costs are based on identical sized plants operating at the same plant factor for each type of fuel and do not include any costs for transmitting the energy to market. The at-market cost of generation from coal-fired plants might be increased a greater amount by the addition of transmission costs since a number may be located near the mine, while the gas-fired and nuclear-fired plants may be located near load centers.

Cost of thermal generation throughout the study period will depend on a number of variables including the type and cost of the fuel utilized, the investment cost of the plants, and plant locations. The variation in generation costs due to plant locations were not projected. Fuel costs utilized were taken from the fuels survey conducted by the Task Force of Fossil Fuels Resources and represent regional averages of the fuel costs projected in the survey. Investment costs were based on current price levels and are shown to increase for gas and coal-fired plants in the latter part of the study period. Investment costs per kw of nuclear-fired plants were reduced during the study period.

The estimates summarized in the above tabulation are shown to indicate the competitiveness of generation throughout the study period from plants fired by the three major fuels in the SCRAC region.

Cost Comparison of Thermal Generation [1]

	Natural Gas	Coal	Nuclear
		Current Period	
Plant Size, Mw	1, 000	1, 000	1, 000
Unit Size, Mw	500	500	500
Construction Cost, $/kw	90	125	[2] 215
Fuel Cost, ¢/MBtu	22	25	....
Fixed Charge Rate, %	14. 37	14. 37	14. 87
Fixed Charges, $/kw	12. 93	17. 96	31. 97
Fixed Operating & Maintenance and Administrative & General, $/kw	2. 27	3. 26	2. 06
Total, $/kw	15. 20	21. 22	34. 03
Total Capacity, Mills/kwh @ 80%	2. 16	3. 02	4. 84
Energy Cost, Mills/kwh [3]	2. 18	2. 40	1. 35
Total Cost, at-site, Mills/kwh	4. 34	5. 42	6. 19
		1975–1980	
Plant Size, Mw	1, 500	1, 500	1, 500
Unit Size, Mw	750	750	750
Construction Cost, $/kw	90	125	[2] 170
Fuel Cost, ¢/MBtu	26	25	......
Fixed Charge Rate, %	14. 37	14. 37	14. 87
Fixed Charges, $/kw	12. 93	17. 96	25. 28
Fixed Operating & Maintenance and Administrative & General, $/kw	2. 14	2. 41	2. 69
Total, $/kw	15. 07	20. 37	26. 97
Total Capacity, Mills/kwh @ 80%	2. 15	2. 91	3. 85
Energy Cost, Mills/kwh [3]	2. 48	2. 35	1. 28
Total Cost, at-site, Mills/kwh	4. 63	5. 26	5. 13
		1981–1990	
Plant Size, Mw	2, 000	2, 000	2, 000
Unit Size, Mw	1, 000	1, 000	1, 000
Construction Cost, $/kw	95	130	[2] 140
Fuel Cost, ¢/MBtu	30	25	....
Fixed Charge Rate, %	14. 37	14. 37	14. 87
Fixed Charges, $/kw	13. 65	18. 68	20. 82
Fixed Operating & Maintenance and Administrative & General, $/kw	2. 21	2. 29	1. 50
Total, $/kw	15. 86	20. 97	22. 32
Total Capacity, Mills/kwh @ 80%	2. 26	2. 99	3. 18
Energy Cost, Mills/kwh [3]	2. 75	2. 27	1. 27
Total Cost, at-site, Mills/kwh	5. 01	5. 26	4. 45

[1] The information presented herein was developed and furnished to the Task Force on General Patterns of Generation and Transmission by the Fort Worth Regional Office of the Federal Power Commission.

[2] Construction cost includes initial fuel investment.

[3] Includes variable Operating & Maintenance.

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WEST CENTRAL REGION

POWER SURVEY

1970—1990

A REPORT

to the FEDERAL POWER COMMISSION

prepared by

THE WEST CENTRAL REGIONAL ADVISORY COMMITTEE

PREFACE

This report for the West Central Region of the United States carries forward the analyses and long-range projections for future power development from the Federal Power Commission's first National Power Survey published in 1964.

The rapid pace of electric power development and changing technology made it desirable to update the National Power Survey periodically to reflect the new trends, statistics and opportunities. Consequently, a West Central Regional Advisory Committee to the FPC and five similar Advisory Committees for other regions were established in 1965 to help carry on this activity. The revised FPC order, dated January 10, 1966, establishing these Regional Advisory Committees says in part:

Purpose.—The Regional Advisory Committees will assist the Commission and the Executive Advisory Committee in its work with and for the Commission and specifically in encouraging the utility systems in each region to pursue courses of action consistent with the broad goals of the National Power Survey, in reporting the progress being made in attaining those goals, and in up-dating the guidelines of the Survey. The Committees will facilitate that exploration of all practicable opportunities for more efficient and reliable development and operation of power systems in each region. Meetings of the Committees will constitute forums for the exchange of ideas and for fostering better communication and understanding among all segments of the utility industry in the region. All systems of every segment of the industry would be encouraged to support the analyses through expressions of their needs and desires. The Committees will be consultative only, and they will operate within the limits established by the Commission, recognizing the appropriate corporate and public responsibilities of utility systems, and will function in keeping with the position of the Commission enunciated on many occasions that the National Power Survey is not intended as a blue print or as a means of compelling the construction of particular facilities.

Materials for this report from the West Central Regional Advisory Committee were prepared by four Regional Task Forces on:

1. Load and Energy Projections
2. Inventory of Fossil Fuel Resources
3. General Patterns of Generation and Transmission
4. Coordinated Planning and Development

The West Central Regional Advisory Committee believes that the report provides valuable guidelines for consideration in charting the course of future power development in the West Central Region. The Committee expresses its appreciation to all of those who participated in the development and preparation of this report.

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- Allen Van Wyck, Illinois Power Company.
- Dick A. Witt, Iowa State Commerce Commission.
- George A. Lewis, U.S. Bureau of Reclamation.

CONTENTS

Chapter III

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Chapter V

SUMMARY

The West Central Region comprises about one-fifth of the conterminous United States and includes about 14% of the population. The region is outlined on the map, Figure 1, below.

The region extends from Lake Michigan and the Illinois-Indiana state line on the east to an irregular line through eastern Montana, Wyoming and western Nebraska. In the north-south direction, the area extends from the Canadian border to an irregular mid-continent line including most of Nebraska, northern Missouri and all of Illinois. The West Central Region corresponds to FPC power supply areas 13, 14, 15, 16, 17 (excluding the Kansas City area), 26, 27, 28, and 40.

The principal load centers are located in the eastern half of the region, and are concentrated in the metropolitan areas of Chicago, Milwaukee, Minneapolis-St. Paul, Omaha, Des Moines, Quad Cities and St. Louis. The western portion of the region is an area of low population density and corresponding low load requirements with few major load centers.

The non-coincident peak load for 1965 in the West Central Region was 24,290 megawatts and the projections are 35,930 megawatts for 1970, 70,610 megawatts for 1980, and 131,680 megawatts for 1990 as detailed in the following tabulation. This indicates a load in 1990 of about five and one-half times the 1965 load compared to an anticipated population growth of 40 percent. The total energy used per person is expected to increase from 4,800 kwhr in 1965 to 18,500 kwhr in 1990.

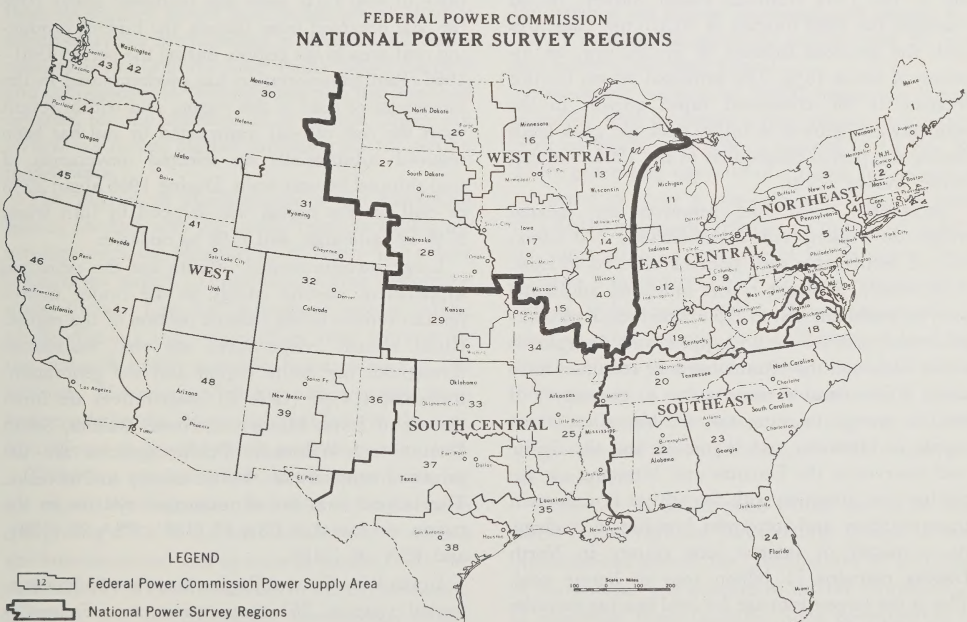

FIGURE 1

356-240 O—70——11

Figure 2.—Load Growth in the West Central Region

[Megawatts]

PSA Area	1965	1970	1980	1990
13	3, 344(W)	4, 660(W)	8, 510(S)	15, 290(S)
14	6, 733(S)	10, 070(S)	19, 810(S)	37, 020(S)
15	2, 943(S)	4, 530(S)	9, 720(S)	18, 770(S)
16	2, 984(W)	4, 280(S)	9, 210(S)	18, 350(S)
17	2, 471(S)	3, 730(S)	7, 160(S)	13, 120(S)
26	649(W)	960(W)	1, 820(W)	3, 390(W)
27	627(W)	910(W)	1, 900(W)	3, 680(W)
28	1, 444(S)	2, 220(S)	4, 390(S)	8, 070(S)
40 (Excl. EEInc)	2, 529(S)	3, 835(S)	7, 355(S)	13, 255(S)
40 (EEInc only)	566(W)	735(W)	735(S)	735(S)
Total (Noncoincidental)	24, 290	35, 930	70, 610	131, 680
Total (Noncoincidental summer season)	23, 920	34, 830	69, 780	130, 240

NOTE: (S) Denotes summer peak.
(W) Denotes winter peak.

The task force based these load projections on a pooling of the independent judgments of the utilities in the region. This current forecast for the region as a whole is higher than that appearing in the 1964 National Power Survey. As an example, the 1980 forecast of 70,610 mw compares with the previous forecast of 61,050 mw, an increase of about 15%. The principal reason for this increase is the continued rapid growth in the economy and growth in utility sales and peak loads during the period subsequent to the 1964 National Power Survey effort.

Substantial fossil fuel resources are located within the region, with approximately 370 billion tons of recoverable coal reserves believed to exist. Additionally, a recent report indicated additional reserves could amount to 225 billion tons of recoverable coal reserves in unmapped and unexplored areas. Although the bituminous coal resources have made a considerable contribution to the supply of electric energy to date, the sub-bituminous coal supply in Montana and Wyoming and the lignite coal reserves in the Dakotas and Montana are receiving new attention with the advent of unit-train transportation and improved burning technology. As a matter of interest, one county in North Dakota contains 71 billion tons of lignite coal. This is the largest tonnage for coal bearing counties in the nation.

The natural gas reserves in the region comprise less than 1% of the total reserves in the United States. The crude oil and natural gas liquid reserves approximate 2% of the total liquid hydro carbon reserves in the United States.

The fossil fuel survey indicated that the average price of coal f.o.b. mine has increased about 10% for coal obtained from Illinois, the highest producing coal area in the region, during the period 1961–1966. Rail transportation has predominated in the movement of coal in this region, and within recent years the cost of coal transported by rail has been reduced substantially on selected movements of coal shipped by unit train. During 1966 about 22% of coal for the region was shipped by unit train, 27% by rail-barge, and 11% by rail-lake.

Large investor-owned utilities are the principal suppliers of electric energy to the major metropolitan centers in the eastern portion of the region. Rural electric cooperatives are well established throughout the entire region and the generation-transmission type (G & T) cooperatives are functioning in Iowa, Minnesota, North Dakota, South Dakota and Wisconsin. Public agencies are the principal suppliers of electric energy in Nebraska. The largest numbers of municipal systems in the region are found in PSA 17 (188), PSA 28 (138), and PSA 16 (110).

In the West Central Region there are 85 investor-owned systems, 261 cooperatives, two Federally-owned systems, and 701 publicly owned systems, comprised mainly of municipal systems and public power districts. Investor-owned companies

serve 83.8 percent of the energy requirements in the region, the cooperatives 2.6 percent and the public agencies (other than Federal) 6.9 percent. The Federal Government generates 6.7 percent of the electric energy in the region, its output being sold principally to municipalities, public power districts and cooperatives. In 1965 about 38 percent of all the power generated by G & T cooperatives in the United States was produced in the West Central Region with cooperatives in PSA 16 alone accounting for about one-half of this amount.

The five largest of the 85 investor-owned electric systems supply nearly 60 percent of the electric loads in the region. Commonwealth Edison Company of Chicago alone accounts for about 27 percent and Union Electric Company of St. Louis for about 11 percent of the regional load. The largest municipal system in the region is Springfield, Illinois, which had a peak load in 1967 of 170 megawatts or about one-half percent of the total regional load.

Public power districts are the principal suppliers of electric power in Nebraska. Many towns in the state are served by municipal systems. Some of the municipalities provide their own generation but most obtain their power from public power districts which carry out the principal generation and transmission functions in the state. Public power districts and cooperatives in Nebraska are also the principal agencies for the distribution of power. There are no investor-owned utilities providing electric service in Nebraska.

The Bureau of Reclamation is the marketing agency for hydroelectric power from Federal projects located in the Missouri River Basin. The power is marketed largely to customers having preference under Federal Law, i.e., municipal systems, public power districts and cooperatives, over a transmission network which generally has a voltage of 230 kilovolts. Numerous wheeling arrangements have been made by the Bureau with utilities in the area for delivery of power to such preference customers.

There is a total of 1,049 electric systems serving the region. With the exception of 71 isolated systems comprising .57% of the total service, all the systems are interconnected and operate in parallel with the vast majority of electric utilities in the United States. By 1970, the interconnecting transmission system will be overlaid with a 345 kv transmission system in the eastern half of the region and an overlaying EHV system in the western half will have been begun. The pattern of transmission development anticipates that the 345 kv system in the eastern half will be substantially augmented during the 1970–1980 period and a 765 kv system will have been started. In the western half of the region the transition to a 500 kv system will be initiated. By 1990, several east to west 765 kv transmission lines are anticipated with their extension through western Minnesota, the Dakotas and the state of Nebraska at 500 kv to interconnect with the western systems.

Consideration of probable increasing fossil fuel costs, increasing concern for air pollution, fossil fuel transportation difficulties, and the anticipation of relative decreasing nuclear fuel costs with the development of fast breeder reactors have resulted in a considerable emphasis on nuclear generating plants. Although about 90% of the electric energy produced in the region is presently supplied by fossil-fuel generation, by 1990 nuclear generating capacity is anticipated to comprise 57% of the region's capacity. Nuclear generation is expected to supply nearly 70% of the region's energy requirements by that time. While the quantity of coal burned annually is indicated to increase from 51 million tons in 1966 to 69 million tons in 1975, the regional use of coal apparently will remain relatively constant at about 65 million tons for the remainder of the study period.

Generating capacity of 79,832 megawatts is projected by 1980 to supply a non-coincident summer peak of 69,780 mw with a reserve of 15.6%. By 1990, generating capacity of 151,041 megawatts is projected to cover a non-coincident summer peak of 130,240 megawatts reflecting a reserve of 16.6%. An importation of 800 mw of hydro power from Canada is included in each of these reserve calculations. Additional reserve of an undetermined amount exists because of the diversity of load between utilities within the season. About half of the 1990 capacity is shown to be in units of 800 megawatts or larger. Generator unit size up to 2000 megawatts and total plant size up to 4000 megawatts are included.

There are six power pools within the region and three major regional coordinating groups. These organizations permit the coordination of planning of transmission and generation and the coordination of operating these facilities. Such coordination is made possible through the direct work of committees and task forces comprised of representatives of individual utilities on the pool level, and of representa-

tives of pools and areas on the regional level. Two offices have been established to provide coordination of hour-to-hour and day-to-day operations.

Additionally, liaison established with contiguous regions provides continuity in the development of interconnections at the boundaries of these organizations and in the operating of mutually-affected facilities. As further coordination develops in increasing depth, it is anticipated that a single regional coordinating organization will evolve with the major planning and operating responsibilities being carried on by five area-wide groups. The interworking between these five groups then will be coordinated within the one principal organization.

CHAPTER I

LOAD AND ENERGY PROJECTIONS

Characteristics of the Region

Demographic

The West Central Region encompasses the states of Illinois, Iowa, Minnesota, North Dakota and Wisconsin in their entirety; substantial portions of Missouri, Nebraska and South Dakota; the upper Peninsula of Michigan; and small sections of Montana and Wyoming. (See Figure A–1). The region includes heavily concentrated commercial and industrial activity within or near such large metropolitan areas as Chicago, St. Louis, Milwaukee and Minneapolis-St. Paul. It includes such rich agricultural areas as the Illinois and Iowa cornbelt, the wheatland areas of Minnesota, Nebraska and the Dakotas, and the dairyland of Wisconsin. The region contains rich mineral deposits such as the iron ore areas of Minnesota and the Michigan upper peninsula, the coal areas of Illinois, and the lignite fields of the Dakotas, Montana and Wyoming.

The region is divided into nine power survey areas (PSA's) with each area possessing social, economic, geographic and climatic characteristics directly influencing future power requirements. PSA's 13, 14, 15, 16, 17 and 40 are located in the more populated eastern half of the region whereas PSA's 26, 27 and 28 are located in the sparsely populated western half of the region. PSA 17 (WCR) includes only the Iowa portion of 17 (F) and excludes the Kansas City area from the West Central Region.

Based on the 1960 Census, the region serves about 14 percent of the population of the contiguous United States. In 1960 this region utilized 11 percent of the total electric energy generated in the contiguous U.S. Population in the region is expected to expand by 42 percent between 1965 and 1990 for an annual growth rate of 1.4 percent. The number of residential customers should closely parallel population growth, probably at a slightly higher rate due to an apparent trend toward smaller families.

It should be noted the boundaries of certain PSA's are not clearly defined for electric utilization or generation purposes. This is especially true in, for example, PSA 27. A major utility in this area also markets in several other PSA's. With greater use of high voltage transmission it is becoming more frequent for generating facilities furnishing load in one area to be located in another PSA closer to the fuel supply. Also, because of high voltage transmission greater amounts of energy are flowing in energy transactions among utilities both within and without a given PSA.

This problem shows up in PSA 27 in the table on classified energy sales, specifically on losses. The losses are based on all energy flowing in and through the area while the net energy figure is the sum of the losses plus all energy sales in the geographic area. Since PSA 27 is expected to be a large energy exporter, losses rise to a disproportionately large percentage of net energy.

Power Requirements

The energy requirements of the area represent the sum of the sales plus losses expected for each individual utility in the area. Similarly, peak demands represent the sum of the non-coincident summer or winter demands of each individual utility in the area. In the first case, except for minor data consistency problems, this is a meaningful statistic. However, in the case of peak demands it must be noted that such computed totals may be substantially different from the coincident demand which might be recorded in the total area or region.

The difference between the sums reported and actual peak coincident demand represents diversity among loads for each of the reporting utilities. That is, the summer peak might occur in July for utility A and in August for utility B. The sum of these reported peaks will be larger, and possibly substan-

tially larger, than the peak demand reached at the same time for both utilities A and B. It should be noted that the actual coincident peak may be at a different time and even different day than that of the peak demand for either of the individual utilities.

The sums of non-coincident peak demands, however, do indicate the general rate of growth to be expected in peak loads as well as the probable timing of the change between winter and summer peaks. The load factors, based on such peaks, are also meaningful in that it is expected that the amount of diversity among utilities will probably neither increase nor decrease a great deal over the period of the study.

Power requirements for the West Central Region in 1965 amounted to 126.8 billion kilowatthours with an associated peak demand of 24.3 million kilowatts. This resulted in a load factor of 59.6 percent. For 1990 the power requirements are estimated at 698.3 billion kilowatthours and 131.7 million kilowatts. This would result in a load factor of 60.5 percent. However, during the interim load factors are expected to decrease slightly before returning to 1965 levels around 1980.

The annual growth rate of energy for the projected periods is just over 7 percent. This matches the growth rate estimated for the contiguous United States over the same period. However, Figure A–2 shows the utilities in the region are projecting a decreasing growth rate, starting at nearly 8 percent annually and declining to about 6½ percent by the decade of the 1980's.

This growth in energy sales reflects the growing population of the region and its increasing demand for electricity. Table A–8 shows total energy used per person going from nearly 4,800 kwh in 1965 to almost 18,500 kwh by 1990. The same table shows this increase to be both in residential use and in commercial and industrial use. Average kwh residential use per customer is expected to increase by a factor of more than four. Commercial and industrial kwh use per capita is expected to increase by a factor of nearly four.

These forecasts envision a substantial increase in the use of electricity with devices presently known; for example, growing use of air conditioning, more intensive lighting, greater use of electric arc furnaces in the steel industry, etc. They also envision electricity continuing to make inroads in the markets of competitive fuels. The major such example is in electric heating but also extends to other uses such as cooking, process heating, etc. Finally these forecasts envision the continuing development of electric energy utilizing devices, some even today undreamed of, which meet consumer's desires for convenience. One major such potential device is the electric car.

The declining load factor for the next few years shown in Table A–10 is due to the rapid rise in summer peak loads. This is caused by the sharp increase in the acceptance of air conditioning as well as the intensive use of pumping energy for irrigation in some of the more rural PSA's. Also the decrease in the high load factor sales to AEC from Electric Energy, Inc. affects this figure.

In 1960, only four of the PSA's had summer peaks higher than winter peaks. Only two of these four had peaks which were substantially different. By 1965, five PSA's were summer peaking, all by fair margins. By 1980 and 1990 all but two PSA's are expected to be summer peaking.

Classified Sales

Energy sales are classified by type of use and broadly defined as farming, irrigation, residential, industrial, commercial, street lighting and electric transportation. These classifications must be viewed with caution. One utility, principally because of its rate structures, may not report customers in the same classification as would another utility. For example: many farm customers are not segregated from residential, much irrigation load is not separately metered, some apartment customers are master metered and hence fall under the commercial class, and some utilities do not distinguish between commercial and industrial customers. With these limitations in mind, certain characteristics of the region can be discussed.

The largest share of the total regional energy in 1965 was industrial with 38 percent, followed by 23 percent for residential and 17 percent for commercial. By 1990 it is expected these three loads as a group will require approximately the same share of the regional energy despite a decline in the industrial share. Residential requirements are expected to increase from 23 percent of the total energy in 1965 to 27 percent in 1990. The commercial share is expected to increase slightly from 17 percent to 18 percent during the same period. The industrial share is projected to decrease from over 38 percent to less than 36 percent. Losses for the entire region are expected to decline from over 9 percent to less than 8 percent. This is in

face of expected increases in inter-area and intra-area transmission of energy. The decrease in losses comes from the more than offsetting increases in voltage levels of transmission facilities. The regional energy required per capita will increase at an annual rate of 5.6 percent, while the commercial and industrial per capita use will increase at a rate of 5.4 percent for the period forecast.

Forecasting Methodology

The Task Force considered several different alternatives to forecast the energy and loads for the Region. Rather than making its own analyses of probable trends, it decided to pool the independent judgments of the utilities in the Region.

A survey was prepared in September of 1966 and sent to all utilities with 1965 energy sales over 150,000 Mwh. Some of the individual utility forecasts appeared quite optimistic while others were quite conservative. The composite tended to balance the extremes and fairly express the best judgment of the group. This data was used as the basis of extending through 1990 the PSA energy and load as accumulated by the FPC regional office. These data are shown in Tables A–1 to A–6.

Energy projections were tested with population projections of the Bureau of Census. The energy and load data were also tested for consistency by checking load factors. These data are shown in Tables A–7 to A–10.

Certain unusual patterns in growth were segregated from the energy and load patterns of individual PSA's and forecast separately. These are discussed in greater detail in a following section.

Tables showing energy projections for classes of service were derived by allocating the total forecast for each PSA. Historically total energy series have grown with a great degree of regularity. While the Task Force views the total forecast with a certain degree of confidence, the patterns of growth in individual classes may be in substantial error. The ebb and flow in technological development of energy utilizing devices with application for each class have been reflected in the greater irregularity of energy growth by classes of service.

It should be noted that these forecasts represent the composite thinking of the major utilities in the region in late 1967. Changes in individual utility forecasts were incorporated until early 1968 although no systematic resurvey of all systems was made. At this point the projections were given to the various task forces in the region for their work.

Several utilities have indicated changes in their forecasts since that time. These changes have not been reflected as an expedient to completing the Region's reports. It is felt that no reported change was of such magnitude as to invalidate the conclusions of either this Task Force or others who have used them as a basis of their conculsions.

Comparison of Current Forecast to 1964 National Power Survey Forecast

The current forecast for the Region as a whole and for each PSA is substantially higher than those in the 1964 National Power Survey except for PSA 40. In the latter case the 1964 National Power Survey did not separate the load and energy projections of Electric Energy, Inc. from the remainder of PSA 40. Were this possible, it is probable PSA 40 would reflect the same relationship as the other PSA's. Comparisons of Task Force estimates with the original NPS forecasts can be seen in the following tables:

Peak [1] Forecast (In Megawatts)

PSA	1965 NPS (est.)	1965 Actual	1970 NPS (est.)	1970 Task Force (est.)	1980 NPS (est.)	1980 Task Force (est.)
13	3, 500	[2] 3, 344	4, 800	[2] 4, 660	8, 700	8, 510
14	6, 500	6, 733	8, 700	10, 070	15, 300	19, 810
15	2, 600	2, 943	3, 700	4, 530	6, 800	9, 720
16	3, 300	[2] 2, 984	4, 600	4, 280	9, 200	9, 210
17 (WCR)	[3] 2, 450	2, 471	[3] 3, 400	3, 730	[3] 6, 200	7, 160
26	680	[2] 649	930	[2] 960	1, 710	[2] 1, 820
27	650	[2] 627	900	[2] 910	1, 630	[2] 1, 900
28	1, 420	1, 444	2, 000	2, 220	3, 610	4, 390
40 (Incl. EEInc.)	3, 300	3, 095	4, 500	4, 570	7, 900	8, 090
Total Region	24, 400	24, 290	33, 530	35, 930	61, 050	70, 610

[1] Non-coincident sum of individual peaks.
[2] Winter peak.
[3] Adjusted to exclude (17F) except Iowa.

Energy Forecast

[In millions of kwh]

PSA	1965 NPS (est.)	1965 Actual	1970 NPS (est.)	1970 Task Force (est.)	1980 NPS (est.)	1980 Task Force (est.)
13	18, 400	18, 881	25, 200	27, 400	45, 700	50, 500
14	33, 900	35, 325	45, 800	52, 300	80, 800	105, 000
15	13, 500	13, 800	18, 900	20, 400	35, 300	43, 800
16	15, 900	15, 562	22, 400	23, 800	44, 100	52, 800
17 (WCR)	[1] 12, 400	12, 604	[1] 17, 400	19, 600	[1] 32, 700	38, 100
26	2, 900	2, 987	4, 000	4, 300	8, 100	8, 400
27	3, 300	3, 471	4, 600	4, 800	8, 400	9, 500
28	5, 900	5, 957	8, 600	9, 100	17, 000	18, 100
40 (Incl. EEInc.)	20, 300	18, 249	26, 400	22, 200	45, 500	44, 300
Total Region	126, 500	126, 836	173, 300	183, 900	317, 600	370, 500

670 7.7 7.370

[1] Adjusted to exclude (17F) except Iowa.

The principal reason for these differences has been the continued rapid growth in the economy and subsequent growth in utility energy sales and peak loads. In 1963 (the period during which the earlier forecasts were being made) the industry foresaw a decrease in rate of growth. This decrease in growth rate has not taken place in the last five years.

Long range forecasts of electric energy requirements have fallen short of actual experience in many cases. This has been usually due either to the forecaster's uncertainty of continuing rapid expansion of the economy or to his uncertainty of new developments. Some of the chief reasons for the rise in popularity of electric energy beyond previous expectations are: growth in commercial and industrial applications of electric energy; rapid growth in population and household formations accompanied by an increase in real income per household; extension of electric service to the rural areas of the

nation; decrease in per unit cost of electricity; and the rapid acceptance of air conditioning, and recently of electric space heating.

This Task Force is reflecting a decrease in rate of growth as indicated by the survey of individual utility forecasts. In the majority of cases and for the Region as a whole, the rate of growth remains higher than those forecast in the 1964 National Power Survey.

These projections by the Task Force envision continuing developments of other electrical applications, perhaps even unknown today, which will satisfy consumer desires for convenience and economy. However, the present growth rate of residential air conditioning will decline as it approaches high saturation levels during the 1970's and 1980's. Similarly, the growth rate of electric heating, both residential and commercial, will moderate as its saturation level increases during the 1980's. Even with this moderation in rate of growth the projections show per capita use of electricity will nearly quadruple between 1965 and 1990.

In contrast, total energy from all sources is projected to less than triple during this period of time. It appears reasonable to assume that as electric energy increases its share of the total energy market, the growth rate of electric energy in its newly enlarged energy market will tend to decline slightly.

% Annual Rate of Growth—Energy Forecast

PSA	Estimated					
	1965–1970		1970–1980		1980–1990	
	NPS	Task Force	NPS	Task Force	NPS	Task Force
13	6. 5	7. 7	6. 1	6. 3	N/A	6. 1
14	6. 2	8. 2	5. 8	7. 2	N/A	6. 4
15	7. 0	8. 1	6. 4	7. 9	N/A	6. 9
16	7. 1	8. 8	7. 0	8. 3	N/A	7. 1
17 (WCR)	7. 0	9. 2	6. 5	6. 9	N/A	7. 0
26	6. 6	7. 5	7. 3	6. 9	N/A	6. 7
27	6. 9	6. 7	6. 2	7. 1	N/A	6. 8
28	7. 8	8. 8	7. 1	7. 1	N/A	6. 3
40 (Incl. EEInc.)	5. 4	4. 0	5. 6	7. 2	N/A	6. 1
Total Region	6. 5	7. 7	6. 2	7. 3	N/A	6. 5

% Annual Rate of Growth—Peak Load Forecast

PSA	Estimated					
	1965–1970		1970–1980		1980–1990	
	NPS	Task Force	NPS	Task Force	NPS	Task Force
13	6. 5	6. 9	6. 1	6. 2	N/A	6. 0
14	6. 0	8. 4	5. 8	7. 0	N/A	6. 4
15	7. 3	9. 0	6. 3	7. 9	N/A	6. 8
16	6. 9	7. 5	7. 2	8. 0	N/A	7. 1
17 (WCR)	6. 8	8. 6	6. 2	6. 7	N/A	6. 2
26	6. 5	8. 1	6. 3	6. 6	N/A	6. 4
27	6. 7	7. 7	6. 1	7. 6	N/A	6. 8
28	7. 1	9. 0	6. 1	7. 1	N/A	6. 3
40 (Incl. EEInc.)	6. 4	8. 1	5. 8	5. 9	N/A	5. 6
Total Region	6. 6	8. 1	6. 2	7. 0	N/A	6. 4

Nature of Projection by PSA

PSA 13.—Projections are based on estimates of utilities serving about 85% of the total area energy requirements. Summer peaks were expected to exceed winter peaks after 1975 resulting in a continually higher load factor through 1990 as shown in Table A–10. Utilities in the area now believe that summer peaks may exceed winter peaks at an earlier date. The Task Force projections are higher than the NPS due to unusual load growth in the area, particularly in the taconite mining industry.

PSA 14.—Estimated growth rates of utilities serving about 90% of the total PSA energy were applied to actual total area energy and load data to project future trends. Energy growth rates are expected to be about 8.2% annually through 1970 and to decrease for the next fifteen years back to 6.4% annually by 1985. Summer peak loads are also expected to follow the same pattern; however, greater space heating demand will cause winter peaks to rise at an increasing rate through 1985.

PSA 15.—Projections are based on estimates of utilities accounting for about 90% of total energy. It is expected that the growth rate for summer peaks will exceed that for winter peaks for some time, but that in the long run the growth rate for winter peaks may become dominant.

PSA 16.—Projections are based on forecasts of utilities serving approximately 75% of the energy in the area. The annual peak is expected to shift from winter to summer by 1970 and it is anticipated that the peak load will experience a high rate of growth through 1980 after which the rate of growth will decline. The energy projection exhibits a variation in rate of growth which reflects a forecast for a very large increase in taconite mining load. Load factors are expected to increase somewhat in later years as use of electric space heating increases.

PSA 17 (WCR).—Almost 70% of the total is based on utility projections. As noted in the foregoing tables, the totals are proportionally adjusted to exclude (17F) except Iowa.

PSA 26.—Forecasts were obtained from utilities serving only approximately 60% of the energy in the area. The remaining energy was treated on the basis of projecting one-half at a rate of growth consistent with that of U.S. Bureau of Reclamation customers and the other half at the rate projected for the utilities in the area. The annual peak load is expected to occur in the winter throughout the forecast period. The area has experienced a very high rate of growth in recent years, especially in peak demand. This rate is expected to subside after 1970 and the declining load factor related to the high growth period is expected to recover somewhat in the later years.

PSA 27.—An estimated two-thirds of the total area energy is supplied by the U.S. Bureau of Reclamation and Basin Electric Power Cooperative. The remainder is served by three other utilities. The USBR-Basin Electric energy portion is forecasted to increase at a faster rate than the composite growth rate of the portion supplied by the utilities.

PSA 28.—Projected growth rates were based on a pooling of estimates by Nebraska Public Power System and Omaha Public Power District serving virtually the entire area. Increasing load growth is anticipated due to industrial and agricultural expansion in the area because of excellent labor and water resources, and the development of power and fuel resources in the Missouri River Basin.

PSA 40 (Excl. EEInc.).—Projected growth rates were based on estimated growth of utilities serving about 94% of the energy for the total area. Utilities in the area currently believe that load and energy requirements will be higher than their projections made over a year ago, particularly for the 1975–1990 period. However, a revision was not reflected in order to preserve consistency with the projections of other areas within the region.

PSA 40 (EEInc. only).—The Electric Energy Inc. load and energy projections were separated from the projections of the PSA 40 utilities so as not to distort future growth patterns of this area. EEInc. projections were based on data supplied by the Atomic Energy Commission.

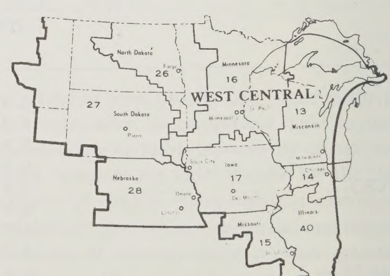

FIGURE A-1

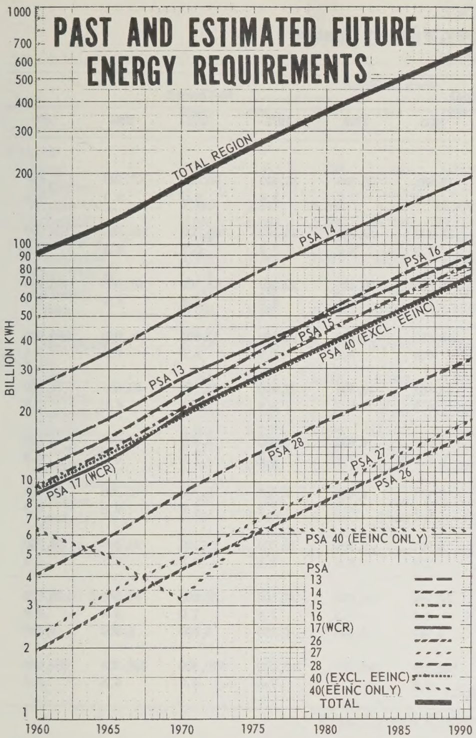

FIGURE A-2

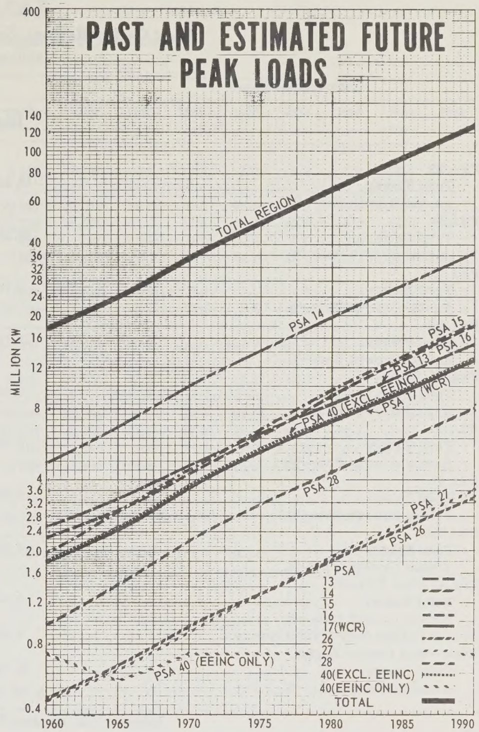

FIGURE A-3

TABLE A-1

West Central Region—Summary of Energy Forecasts

(Millions of kwh)

	Actual		Estimated				
	1960	1965	1970	1975	1980	1985	1990
PSA 13:							
Total Energy	13,529	18,881	27,400	37,800	50,500	67,700	91,300
Annual Growth Rate—%		6.9	7.7	6.6	6.0	6.0	6.2
PSA 14:							
Total Energy	25,207	35,325	52,300	75,800	105,000	143,000	195,000
Annual Growth Rate—%		7.0	8.2	7.7	6.7	6.4	6.4
PSA 15:							
Total Energy	9,742	13,800	20,400	30,000	43,800	61,200	85,100
Annual Growth Rate—%		7.2	8.1	8.0	7.9	6.9	6.8
PSA 16:							
Total Energy	11,178	15,562	23,800	34,800	52,800	74,600	105,000
Annual Growth Rate—%		6.8	8.9	7.9	8.7	7.2	7.1
PSA 17 (WCR):							
Total Energy	9,021	12,604	19,600	27,400	38,100	53,300	74,600
Annual Growth Rate—%		6.9	9.2	6.9	6.8	6.9	7.0
PSA 26:							
Total Energy	1,994	2,987	4,300	6,000	8,400	11,600	16,100
Annual Growth Rate—%		8.4	7.6	6.9	7.0	6.7	6.8
PSA 27:							
Total Energy	2,287	3,471	4,800	6,800	9,500	13,200	18,300
Annual Growth Rate—%		8.7	6.7	7.2	6.9	6.8	6.8
PSA 28:							
Total Energy	4,150	5,957	9,100	13,000	18,100	24,500	33,300
Annual Growth Rare—%		7.5	8.8	7.4	6.8	6.2	6.3
PSA 40 (Excl EEInc):							
Total Energy	9,511	13,262	19,000	27,100	38,000	52,800	73,300
Annual Growth Rate—%		6.9	7.5	7.4	7.0	6.8	6.8
PSA 40 (EEInc Only): Total Energy	6,519	4,987	3,200	6,300	6,300	6,300	6,300
Total—West Central Region:							
Total Energy	93,138	126,836	183,900	265,000	370,500	508,200	698,300
Annual Growth Rate—%		6.4	7.7	7.6	6.9	6.5	6.6

TABLE A-2

West Central Region—Summary of Estimates

	Millions kwh							% of net energy						
	1960 [1]	1965 [1]	1970	1975	1980	1985	1990	1960 [1]	1965 [1]	1970	1975	1980	1985	1990
PSA-13:														
Farm	883	989	1,530	2,080	2,780	3,660	4,930	6.5	5.3	5.6	5.5	5.5	5.4	5.4
Irrigation	1	5												
Residential	3,712	5,006	7,530	10,470	14,040	18,960	25,660	27.4	26.5	27.5	27.7	27.8	28.0	28.1
Industrial	4,747	7,095	9,780	13,460	17,980	2 ,170	32,590	35.1	37.6	35.7	35.6	35.6	35.7	35.7
St. Lighting	193	286	410	570	760	1,020	1,370	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Commercial	2,423	3,409	5,010	6,950	9,340	12,590	17,070	17.9	18.1	18.3	18.4	18.5	18.6	18.7
Elec. Transp	45	6	20	20	30	30	50	0.3		0.1	0.1	0.1	0.1	0.1
All other	276	455	630	910	1,210	1,620	2,190	2.1	2.4	2.3	2.4	2.4	2.4	2.4
Losses	1,249	1,630	2,490	3,340	4,360	5,650	7,440	9.2	8.6	9.1	8.8	8.6	8.3	8.1
Net energy	13,529	18,881	27,400	37,800	50,500	67,700	91,300	100.0	100.0	100.0	100.0	100.0	100.0	100.0
PSA-14:														
Farm	383	300	500	640	790	1,000	1,270	1.5	0.8	0.9	0.8	0.8	0.7	0.6
Irrigation														
Residential	5,543	8,041	12,580	18,950	27,140	38,320	53,820	22.0	22.8	24.0	25.0	25.8	26.8	27.6
Industrial	9,423	13,246	18,700	26,110	34,810	45,550	59,770	37.4	37.5	35.9	34.5	33.1	31.8	30.7
St. Lighting	335	441	630	870	1,150	1,500	1,950	1.3	1.2	1.2	1.2	1.1	1.0	1.0
Commercial	5,520	8,098	12,500	18,760	26,880	37,680	52,840	21.9	22.9	23.9	24.7	25.6	26.5	27.1
Elec. Transp	407	383	470	610	790	1,000	1,270	1.6	1.1	0.9	0.8	0.7	0.7	0.6
All other	1,195	1,857	2,610	3,870	5,510	7,650	10,630	4.8	5.3	5.0	5.1	5.3	5.3	5.5
Losses	2,401	2,959	4,310	5,990	7,930	10,300	13,450	9.5	8.4	8.2	7.9	7.6	7.2	6.9
Net energy	25,207	35,325	52,300	75,800	105,000	143,000	195,000	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[1] Actual data.

TABLE A-3

West Central Region—Summary of Estimates

	Millions kwh							Percent of net energy						
	1960 [1]	1965 [1]	1970	1975	1980	1985	1990	1960 [1]	1965 [1]	1970	1975	1980	1985	1990
PSA-15:														
Farm	298	392	680	1,090	1,710	2,540	3,750	3.0	2.8	3.3	3.6	3.9	4.2	4.4
Irrigation		2												
Residential	2,400	3,393	5,540	8,230	12,250	18,130	26,520	24.6	24.6	27.2	27.5	28.0	29.6	31.2
Industrial	4,651	6,982	9,660	14,030	20,170	27,270	36,720	47.7	50 6	47.3	46.8	46 0	44.5	43.1
St.Lighting	84	117	180	240	350	430	590	0.9	0.9	0.9	0.8	0.8	0.7	0.7
Commercial	1,256	1,645	2,470	3,660	5,340	7,330	10,000	12.9	11.9	12.1	12.2	12.2	12.0	11.8
Elec. Transp	16							0.2						
All other	152	185	290	490	790	1,250	1,880	1.6	1.3	1.4	1.6	1.8	2.1	2.2
Losses	885	1,086	1,580	2,260	3,190	4,250	5,640	9.1	7.9	7.8	7.5	7.3	6.9	6.6
Net Energy	9,742	13,800	20,400	30,000	43,800	61,200	85,100	100.0	100.0	100.0	100.0	100.0	100.0	100.0
PSA-16:														
Farm	1,280	1,674	2,500	3,500	5,090	6,890	9,290	11.5	10.8	10.5	10.0	9.6	9.3	8.8
Irrigation														
Residential	3,045	4,389	6,680	9,780	14,790	20,760	28,940	27.2	28.2	28.1	28.1	28.0	27.8	27.6
Industrial	3,569	5,327	8,530	13,070	20,740	30,570	44,760	31.9	34.2	35.9	37.6	39.3	41.0	42.6
St. Lighting	151	203	320	450	670	910	1,240	1.4	1.3	1.3	1.3	1.3	1.2	1.2
Commercial	1,577	2,089	3,110	4,350	6,300	8,510	11,460	14.1	13.4	13.0	12.5	11.9	11.4	10.9
Elec. Transp														
All Other	297	398	590	850	1,270	1,750	2,400	2.7	2.6	2.5	2.4	2.4	2.3	2.3
Losses	1,259	1,482	2,070	2,800	3,940	5,210	6,910	11.2	9.5	8.7	8.1	7.5	7.0	6.6
Net Energy	11,178	15,562	23,800	34,800	52,800	74,600	105,000	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[1] Actual data.

TABLE A-4

West Central Region—Summary of Estimates

	Millions kwh							Percent of net energy						
	1960 [1]	1965 [1]	1970	1975	1980	1985	1990	1960 [1]	1965 [1]	1970	1975	1980	1985	1990
PSA-17 (WCR):														
Farm	1,594	2,036	3,350	4,710	6,570	9,220	12,930	17.7	16.2	17.1	17.2	17.2	17.3	17.3
Irrigation	6	1												
Residential	2,254	3,051	4,840	6,830	9,590	13,530	19,090	25.0	24.2	24.7	24.9	25.2	25.4	25.6
Industrial	2,319	3,218	5,170	7,250	10,090	14,130	19,770	25.7	25.5	26.4	26.5	26.5	26 5	26.5
St. Lighting	125	162	260	330	420	590	750	1.4	1.3	1.2	1.2	1.1	1.1	1.0
Commercial	1,555	2,539	3,670	5,190	7,290	10,320	14,590	17.2	20.1	18.7	18.9	19.1	19.3	19.6
Elec. Transp	10							0.1						
All Other	186	386	500	700	990	1,320	1,870	2.1	3.1	2.7	2.6	2.6	2.5	2.5
Losses	972	1,210	1,810	2,390	3,150	4,190	5,600	10.8	9.6	9.2	8.7	8.3	7.9	7.5
Net Energy	9,021	12,604	19,600	27,400	38,100	53,300	74,600	100.0	100.0	100.0	100.0	100.0	100.0	100.0
PSA-26:														
Farm	471	678	1,080	1,510	2,100	2,830	3,760	23.6	22.7	25.1	25.3	25.1	24.4	23.3
Irrigation														
Residential	624	859	1,250	1,660	2,190	2,830	3,660	31.3	28.7	29.1	27.7	26.1	24.4	22.7
Industrial	183	435	690	1,150	1,910	3,100	4,960	9.1	14.5	16.0	19.2	22.7	26.7	30.8
St. Lighting	31	44	60	80	110	140	180	1.6	1.6	1.4	1.3	1.3	1.2	1.1
Commercial	378	489	580	740	950	1,220	1,590	19.0	16.4	13.5	12.4	11.3	10.5	9.9
Elec. Transp														
All Other	52	160	180	260	370	500	690	2.6	5.4	4.1	4.2	4.3	4.4	4.3
Losses	255	323	460	600	770	980	1,260	12.8	10.8	10.8	9.9	9.2	8.4	7.9
Net Energy	1,994	2,987	4,300	6,000	8,400	11,600	16,100	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[1] Actual data.

TABLE A-5

West Central Region—Summary of Estimates

	Millions kwh							Percent of net energy						
	1960 [1]	1965 [1]	1970	1975	1980	1985	1990	1960 [1]	1965 [1]	1970	1975	1980	1985	1990
PSA-27:														
Farm	333	498	670	890	1,170	1,520	1,970	14.6	14.3	13.9	13.1	12.3	11.5	10.7
Irrigation	28	18	30	40	50	60	80	1.2	.5	.7	.6	.5	.5	.5
Residential	518	685	980	1,320	1,750	2,290	2,980	22.7	19.7	20.3	19.4	18.4	17.4	16.3
Industrial	297	422	520	690	900	1,160	1,490	13.0	12.2	10.9	10.2	9.4	8.7	8.2
St. Lighting	36	50	70	90	120	150	200	1.6	1.5	1.4	1.3	1.2	1.2	1.1
Commercial	389	583	820	1,130	1,510	2,010	2,640	17.0	16.8	17.1	16.6	16.0	15.2	14.4
Elec. Transp														
All Other	105	277	460	780	1,310	2,190	3,620	4.6	8.0	9.5	11.4	13.8	16.6	19.8
Losses	581	938	1,250	1,860	2,690	3,820	5,320	25.3	27.0	26.1	27.3	28.3	28.9	29.0
Net Energy	2,287	3,471	4,800	6,800	9,500	13,200	18,300	100.0	100.0	100.0	100.0	100.0	100,0	100.0
PSA-28:														
Farm	527	688	980	1,300	1,670	2,060	2,560	12.7	11.6	10.8	10.0	9.2	8.4	7.7
Irrigation	50	62	70	90	110	120	130	1.2	1.0	0.8	0.7	0.6	0.5	0.4
Residential	1,067	1,515	2,430	3,530	4,940	6,740	9,160	25.7	25.4	26.7	27.1	27.3	27.5	27.5
Industrial	900	1,335	2,140	3,210	4,670	6,570	9,260	21.7	22.4	23.5	24.7	25.8	26.8	27.8
St. Lighting	68	90	130	140	200	220	270	1.6	1.5	1.4	1.1	1.1	0.9	0.8
Commercial	938	1,465	2,210	3,240	4,610	6,420	8,930	22.6	24.6	24.3	24.9	25.5	26.2	26.8
Elec. Transp	7	6						0.2	0.1					
All Other	153	193	230	260	270	290	330	3.7	3.2	2.5	2.0	1.5	1.2	1.0
Losses	440	603	910	1,230	1,630	2,080	2,660	10.6	10.2	10.0	9.5	9.0	8.5	8.0
Net Energy	4,150	5,957	9,100	13,000	18,100	24,500	33,300	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[1] Actual data.

TABLE A-6

West Central Region—Summary of Estimates

	Millions kwh							Percent of net energy						
	1960 [1]	1965 [1]	1970	1975	1980	1985	1990	1960 [1]	1965 [1]	1970	1975	1980	1985	1990
PSA-40 (Excl. EEInc):														
Farm	877	1,108	1,680	2,380	3,340	4,590	6,300	9.2	8.4	8.8	8.8	8.8	8.7	8.6
Irrigation	4	4												
Residential	2,128	2,884	4,400	6,380	9,110	12,870	18,170	22.4	21.7	23.2	23.5	24.0	24.4	24.8
Industrial	3,968	5,662	8,200	11,900	16,890	23,730	33,300	41.7	42.7	43.2	43.9	44.4	44.9	45.4
St. Lighting	69	90	130	190	270	370	440	0.7	0.7	0.7	0.7	0.7	0.7	0.6
Commercial	1,294	1,918	2,550	3,520	4,780	6,440	8,720	13.6	14.5	13.4	13.0	12.6	12.2	11.9
Elec. Transp														
All other	187	283	400	570	800	1,160	1,540	2.0	2.1	2.1	2.1	2.1	2.2	2.1
Losses	984	1,313	1,640	2,160	2,810	3,640	4,830	10.4	9.9	8.6	8.0	7.4	6.9	6.6
Net Energy	9,511	13,262	19,000	27,100	38,000	52,800	73,300	100.0	100.0	100.0	100.0	100.0	100.0	100.0
PSA-40 (EEInc Only):														
Net Energy	6,519	4,987	3,200	6,300	6,300	6,300	6,300	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total—West Central Region:														
Farm	6,646	8,363	12,970	18,100	25,220	34,310	46,760	7.1	6.6	7.0	6.8	6.8	6.8	6.7
Irrigation	89	90	100	130	160	180	210	0.1	0.1	0.1	0.1			
Residential	21,291	29,823	46,230	67,150	95,800	134,430	188,000	22.9	23.5	25.1	25.3	25.9	26.5	26.9
Industrial [2]	36,576	48,709	66,590	97,170	134,460	182,550	248,920	39.3	38.4	36.2	36.7	36.3	35.9	35.7
St. Lighting	1,092	1,483	2,190	2,960	4,050	5,330	6,990	1.2	1.2	1.2	1.1	1.1	1.0	1.0
Commercial	15,330	22,235	32,920	47,540	67,000	92,520	127,840	16.4	17.5	17.9	17.9	18.1	18.2	18.3
Elec. Transp	485	395	490	630	820	1,030	1,320	0.5	0.3	0.3	0.2	0.2	0.2	0.2
All Other	2,603	4,194	5,890	8,690	12,520	17,730	25,150	2.8	3.3	3.2	3.3	3.4	3.5	3.6
Losses	9,026	11,544	16,520	22,630	30,470	40,120	53,110	9.7	9.1	9.0	8.6	8.2	7.9	7.6
Net Energy	93,138	126,836	183,900	265,000	370,500	508,200	698,300	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[1] Actual data.

[2] Including Electric Energy, Inc.

TABLE A-7

West Central Region—Projections

(Population—Persons Per Household—Customers)

PSA	Population projections [1] (Thousands)							Persons per household projections							Customer projections (Thousands)						
	1960 [2]	1965 [2]	1970	1975	1980	1985	1990	1960 [2]	1965 [2]	1970	1975	1980	1985	1990	1960 [2]	1965 [2]	1970	1975	1980	1985	1990
13	3,673	3,839	4,087	4,322	4,778	5,182	5,626	3.36	3.31	3.31	3.31	3.31	3.30	3.30	1,094	1,159	1,235	1,306	1,444	1,570	1,705
14	7,264	7,642	8,089	8,694	9,408	10,194	11,066	3.72	3.54	3.42	3.35	3.30	3.30	3.30	1,955	2,161	2,365	2,595	2,851	3,089	3,353
15	2,306	2,390	2,447	2,585	2,756	2,947	3,159	2.96	2.86	2.86	2.86	2.85	2.85	2.85	779	837	856	904	967	1,034	1,108
16	3,670	3,810	4,059	4,384	4,766	5,184	5,634	3.42	3.34	3.33	3.33	3.32	3.32	3.31	1,072	1,142	1,219	1,317	1,436	1,561	1,702
17 (WCR)	3,167	3,178	3,287	3,461	3,677	3,922	4,181	3.35	3.18	3.18	3.18	3.17	3.17	3.16	945	998	1,034	1,088	1,160	1,237	1,323
26	873	899	944	1,004	1,077	1,158	1,247	3.52	3.46	3.46	3.46	3.45	3.45	3.45	248	260	273	290	312	336	361
27	674	695	740	780	829	885	947	3.30	3.22	3.22	3.21	3.21	3.20	3.20	204	216	230	243	258	277	296
28	1,305	1,361	1,428	1,492	1,576	1,672	1,767	3.39	3.23	3.14	3.05	3.01	3.01	3.01	385	422	455	489	523	556	587
40	2,719	2,861	3,028	3,255	3,522	3,817	4,143	3.25	3.20	3.13	3.06	3.01	2.98	2.98	837	894	967	1,064	1,170	1,281	1,390
Total	25,653	26,675	28,109	29,976	32,389	34,961	37,770	3.41	3.30	3.26	3.22	3.20	3.20	3.19	7,519	8,089	8,634	9,296	10,121	10,941	11,825

[1] Based on Series II-B, Bureau of Census P-25, No. 326, February 1966.
[2] Actual data.

TABLE A-8

West Central Region—Estimated Kilowatthour Use

PSA	Total energy kwh use/person							Commercial and industrial kwh use/person							Residential and farm kwh use/customer						
	1960 [1]	1965 [1]	1970	1975	1980	1985	1990	1960 [1]	1965 [1]	1970	1975	1980	1985	1990	1960 [1]	1965 [1]	1970	1975	1980	1985	1990
13	3,683	4,918	6,700	8,750	10,570	13,060	16,230	1,952	2,736	3,620	4,720	5,720	7,090	8,830	4,200	5,173	7,340	9,610	11,650	14,410	17,940
14	3,470	4,622	6,470	8,720	11,160	14,030	17,620	2,057	2,793	3,860	5,160	6,560	8,160	10,180	3,031	3,860	5,530	7,550	9,800	12,730	16,430
15	4,225	5,774	8,340	11,610	15,900	20,770	26,940	2,562	3,610	4,960	6,840	9,260	11,740	14,790	3,463	4,520	7,270	10,310	14,440	19,990	27,320
16	3,046	4,085	5,860	7,940	11,080	14,390	18,640	1,402	1,946	2,870	3,970	5,670	7,540	9,980	4,035	5,309	7,530	10,080	13,840	17,710	22,460
17 (WCR)	2,848	3,966	5,960	7,920	10,360	13,590	17,840	1,223	1,812	2,690	3,590	4,730	6,230	8,220	4,072	5,097	7,920	10,610	13,930	18,390	24,200
26	2,284	3,323	4,560	5,980	7,800	10,020	12,910	643	1,028	1,350	1,880	2,660	3,730	5,250	4,415	5,912	8,530	10,930	13,750	16,850	20,550
27	3,393	4,994	6,490	8,720	11,460	14,920	19,320	1,018	1,446	1,810	2,330	2,910	3,580	4,360	4,172	5,477	7,170	9,090	11,320	13,750	16,720
28	3,180	4,377	6,370	8,710	11,480	14,650	18,850	1,408	2,057	3,050	4,320	5,890	7,770	10,290	4,140	5,220	7,490	9,880	12,640	15,830	19,970
40 [2]	3,498	4,635	6,280	8,330	10,790	13,830	17,690	1,935	2,649	3,550	4,740	6,150	7,900	10,140	3,590	4,465	6,290	8,230	10,640	13,630	17,600
Total [3]	3,631	4,755	6,540	8,840	11,440	14,540	18,490	2,023	2,660	3,540	4,830	6,220	7,870	9,980	3,716	4,720	6,860	9,170	11,960	15,420	19,850

[1] Actual data.
[2] Excludes EEInc.
[3] Includes EEInc.

TABLE A-9

Summary of Load Forecasts

(Peak load mw)

	Actual				Estimated							
	1960		1965		1970		1975		1980		1990	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
PSA 13:												
Peak Loads	2,464	2,564	3,236	3,344	4,500	4,660	6,320	6,380	8,510	8,430	15,290	14,460
Annual Growth Rate—%			5.6	5.5	6.8	6.9	7.0	6.5	6.1	5.7	6.0	5.5
PSA 14:												
Peak Loads	4,783	4,640	6,733	6,190	10,070	8,260	14,350	11,110	19,810	15,150	37,020	28,280
Annual Growth Rate—%			7.1	6.0	8.4	5.9	7.3	6.1	6.7	6.4	6.5	6.4
PSA 15:												
Peak Loads	1,980	1,651	2,943	2,283	4,530	3,170	6,650	4,650	9,720	7,140	18,770	16,960
Annual Growth Rate—%			8.3	6.7	9.0	6.8	8.0	8.0	7.9	9.0	6.8	9.0
PSA 16:												
Peak Loads	2,108	2,296	2,925	2,984	4,280	4,210	6,230	5,800	9,210	8,020	18,350	16,060
Annual Growth Rate—%			6.8	5.4	7.9	7.1	7.8	6.6	8.1	6.7	7.1	7.2
PSA 17 (WCR):												
Peak Loads	1,762	1,801	2,471	2,200	3,730	3,240	5,260	4,420	7,160	5,920	13,120	10,970
Annual Growth Rate—%			7.0	4.1	8.6	8.1	7.1	6.4	6.4	6.0	6.2	6.4
PSA 26:												
Peak Loads	348	476	510	649	720	960	990	1,320	1,370	1,820	2,620	3,390
Annual Growth Rate—%			8.0	6.4	7.1	8.1	6.6	6.6	6.7	6.6	6.7	6.4
PSA 27:												
Peak Loads	372	456	564	627	710	910	1,030	1,310	1,520	1,900	3,010	3,680
Annual Growth Rate—%			8.7	6.6	4.7	7.7	7.8	7.6	8.1	7.7	7.1	6.8
PSA 28:												
Peak Loads	967	778	1,444	1,028	2,220	1,670	3,160	2,390	4,390	3,310	8,070	6,100
Annual Growth Rate—%			8.4	5.7	9.0	10.2	7.3	7.4	6.8	6.7	6.3	6.3
PSA 40:												
(Excluding EEInc) Peak Loads	1,808	1,780	2,529	2,233	3,835	3,325	5,495	4,605	7,355	6,215	13,255	11,105
Annual Growth Rate—%			6.9	4.6	8.7	8.3	7.5	6.7	6.0	6.2	6.1	6.0
PSA 40:												
(EEInc Only) Peak Loads	735	735	565	566	235	735	735	735	735	735	735	735
Total WCR:												
Peak Loads	17,327	17,177	23,920	22,104	34,830	31,140	50,220	42,720	69,780	58,640	130,240	111,740
Annual Growth Rate—%			6.7	5.2	7.8	7.1	7.6	6.5	6.8	6.5	6.4	6.7

TABLE A-10

Summary of Load Forecasts—Load Factors

(Peak loads in mw—Net energy in millions kwh)

	Actual				Estimated							
	1960		1965		1970		1975		1980		1990	
	Peak load	Net energy	Peak load	Net energy	Peak load	Net energy	Peak load	Net energy	Peak load	Net energy	Peak load	Net energy
PSA-13	2,564 (W)	13,529	3,344 (W)	18,881	4,660 (W)	27,400	6,380 (W)	37,800	8,510 (S)	50,500	15,290 (S)	91,300
	60.2		64.5		67.1		67.6		67.8		68.1	
PSA-14	4,783 (S)	25,207	6,733 (S)	35,325	10,070 (S)	52,300	14,350 (S)	75,800	19,810 (S)	105,000	37,020 (S)	195,000
	60.2		59.9		59.3		60.3		60.5		60.1	
PSA-15	1,980 (S)	9,742	2,943 (S)	13,800	4,530 (S)	20,400	6,650 (S)	30,000	9,720 (S)	43,800	18,770 (S)	85,100
	56.2		53.5		51.5		51.6		51.5		51.8	
PSA-16	2,296 (W)	11,178	2,984 (W)	15,562	4,280 (S)	23,800	6,230 (S)	34,800	9,210 (S)	52,800	18,350 (S)	105,000
	55.6		59.5		63.4		63.8		65.5		65.3	
PSA-17 (WCR)	1,801 (W)	9,021	2,471 (S)	12,604	3,730 (S)	19,600	5,260 (S)	27,400	7,160 (S)	38,100	13,120 (S)	74,600
	57.2		58.2		59.9		59.5		60.8		64.9	
PSA-26	476 (W)	1,994	649 (W)	2,987	960 (W)	4,300	1,320 (W)	6,000	1,820 (W)	8,400	3,390 (W)	16,100
	47.8		52.5		51.0		51.8		52.7		54.2	
PSA-27	456 (W)	2,287	627 (W)	3,471	910 (W)	4,800	1,310 (W)	6,800	1,900 (W)	9,500	3,680 (W)	18,300
	57.3		63.2		60.3		58.7		57.2		56.8	
PSA-28	967 (S)	4,150	1,444 (S)	5,957	2,220 (S)	9,100	3,160 (S)	13,000	4,390 (S)	18,100	8,070 (S)	33,300
	49.0		47.1		47.0		47.0		47.0		47.0	
PSA-40 (Excl. EEInc)	1,808 (S)	9,511	2,529 (S)	13,262	3,835 (S)	19,100	5,495 (S)	27,100	7,355 (S)	38,000	13,255 (S)	73,300
	60.1		59.9		56.6		56.3		59.0		63.1	
PSA-40 (EEInc Only)	735	6,519	566	4,987	735	3,200	735	6,300	735	6,300	735	6,300
	100.0		100.0		49.7		97.8		97.8		97.8	
Total WC Region	17,866	93,138	24,290	126,836	35,930	183,900	50,890	265,000	70,610	370,500	131,680	698,300
	59.5		59.6		58.4		59.4		59.9		60.5	

NOTE: (W) Winter peak.
(S) Summer peak.

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CHAPTER II

INVENTORY OF FOSSIL FUEL RESOURCES

Introduction

The purpose of this report is to update the 1964 National Power Survey, Vol. II, Advisory Committee Report No. 21 on Fuels for Electric Generation, prepared by the Fuels Special Technical Committee.

In updating Report No. 21 we have not attempted to change or modify the extensive and authoritative background material in that report, which represents the best advance thinking on industry fuel problems by some of its foremost members. Instead we have supplemented that report where changes have occurred in the price of fuel, the cost of transportation and methods of transport.

The West Central Region fossil fuel reserves are reported in detail by individual counties in each state. The reserves are tabulated by class of reserves as to whether they are "measured," "indicated" or "inferred" and by thickness of the coal beds. Measured reserves are those for which tonnage was computed from direct measurements. Indicated reserves are those for which tonnage was computed partly from specific measurements and partly from responsible assumptions based on available data and geologic evidence. Inferred reserves are those for which quantitative estimates are based on a broad knowledge of the character of the bed or the region, but for which there are few, if any, actual measurements. This detailed information on coal reserves should be useful to system planners in selecting future sites for large thermal power plants.

Other task force committees have prepared reports on load projections, types of generation, air pollution and nuclear power; therefore, this report does not include information on those subjects. If the reader desires information on productive capacity of the coal industry, future projected prices of various fuels or other related information regarding fuels, it is suggested he consult the report of Fuel Resources, Requirements and Costs for Electric Generation in the Eastern United States which was prepared by a committee that included representatives from the Federal Power Commission, the Bureau of Mines and the Office of Oil and Gas, Department of the Interior.

Summary

During the period 1970–1990, electric generation will be dependent upon five basic forms of energy—coal, gas, oil, hydro, and nuclear. This report is concerned primarily with fossil fuels. The availability of approximately 370 billion tons of recoverable coal reserves in the West Central Region is more than sufficient to meet the electric utilities' requirements in this region through the year 2000. A recent report indicates additional reserves in this region could amount to 225 billion tons of recoverable coal reserves in unmapped and unexplored areas.[1] Coal, however, will be faced with continuing pressures from other forms of energy, and based on present trends the most significant competition will be from nuclear energy.

Mechanization and handling of coal at the mine will continue to improve. Some of the new developments in underground mining in recent years have been the use of a mobile bridge conveyor which has increased the productivity from a continuous miner substantially, the underground push button miner, the installation of long wall mining equipment, and the application of computer simulation techniques.

In determining the type of fuel to be used for electric generation a number of factors have to be reviewed and evaluated, each of which will have a bearing on total fuel costs for any one location. The cost of transportation, anti-air pollution devices, storing, handling and disposing of the fuel product are economic factors which can make a low cost fuel the most expensive fuel. Therefore, while a general picture can be drawn of the availability and price of fuels, the final determination

[1]Averitt, Paul, 1968 U.S. Geological Survey.

in selecting a fuel or fuels for a particular plant must be based on the specific facts pertinent to that plant and its location.

A fossil fuel survey questionnaire was sent to twenty-six electric utilities which consume approximately 90 percent of the coal used for electric generation in the West Central Region. The questionnaire inquired as to producing district, tonnage burned, f.o.b. mine price, average BTU per lb. received, cents per million BTU f.o.b. mine, methods of transportation used, freight rate, haulage distance, and tonnage per shipment

This survey indicated that in the period 1961–66 the average price of coal f.o.b. mine has increased from 15.03 to 16.57 cents per million BTU or an increase of 10.18 percent on the coal obtained in District 10 (36 million tons of 46 million tons reported for the region). The average annual increase in the cost of District 10 coal in the five year period 1961–1966 amounts to 1.9 percent per year. Due to the less significant tonnages reported in relationship to tonnage produced, a comparison of the price increases for coal obtained from other districts is not shown.

Rail transportation in the past has predominated in the movement of coal in this region, and within recent years the cost of coal transported by rail has been reduced substantially on selected movements of coal shipped by unit train. Based on the 46 million tons reported in the survey for the year 1966, approximately 10 million tons, or 21.8 percent, were shipped by unit train, 12,200,000 tons, or 26.6 percent, were shipped by rail-barge, and 5,280,000 tons, or 11.5 percent, were shipped by rail-lake. The amount of coal shipped by conveyor and captive shuttle train during the period 1970–1975 will increase by 11,000,000 tons versus a 7,000,000 ton increase for unit train shipments.

The average rail freight cost in the West Central Region for coal shipments in 1966 amounted to $1.97 per ton on a tonnage of 23,500,000 tons, or approximately 46 percent of the coal consumed in this region. The unit train freight rates reported in the survey when compared on a basis which considers railroad ownership of all equipment indicates that the mills per ton mile range from 10.3 mills per ton mile for an 85 mile haul to 7.2 mills for a 138 mile haul and down to 5.0 mills for a 355 mile haul.

Past projections indicated that unit train freight rates could level out at a cost of 4 mills per ton mile for hauls between 350 miles and 600 miles.[2] However, no hauls of 400 to 500 miles at 4 mills were reported. The inability of the utilities to obtain a lower cost than 5 mills per ton mile is partially substantiated by the fact that as of the present date between now and 1975 approximately 10,000 megawatts of nuclear capacity is planned or considered for installation in the West Central Region.

In the five year period 1961–1966 the consumption of gas for thermal electric generation increased from 0.223 to 0.260 trillion cubic feet or at an average annual rate of 3.11 percent compared to a 7.73 percent average annual increase in coal consumption in the same period. The average cost of gas for the region in the same period increased from 25 to 25.3 cents per million BTU or by 1.2 percent.

Table A indicates the electric generation produced by coal fired plants in the West Central Region will increase from 124.8 billion Kwh in 1970 to 155.3 billion Kwh in 1990 and nuclear generation will increase from 17.5 billion Kwh to 489.1 billion Kwh in the same period. Table B indicates coal consumption will increase from 60.4 million tons in 1970 to 65.7 million tons in 1990.

Table 1 lists the remaining coal reserves in the West Central Region by percent sulfur content and approximately 72.7 percent of the reserves in the region contain 1.0 percent or less sulfur. However, most of these low sulfur coal reserves are located in the States of Montana and North Dakota and most of the coal consumed in the region is obtained from the State of Illinois.

Table 2 indicates the coal consumed for electric generation in the West Central Region in 1966 had an average sulfur content of 2.8 percent which is slightly more than the 2.3 percent average sulfur content of all coal consumed by the electric utilities in the United States.

The growing demand for air pollution abatement regulations has contributed to a major shift from the use of coal for electric generation to nuclear energy. In the West Central Region in 1966 approximately 72 percent of the electric generation was produced in coal fired plants and 1 percent by nuclear plants. Present projections illustrate that by 1990 approximately 22 percent of the electric generation in the region will be produced in coal fired plants and 70 percent by nuclear plants.

[2] 1964 National Power Survey, Vol. 2, Advisory Report No. 21, Pg. 338

TABLE A

West Central Region—Thermal Electric Generation by Type of Fuel and Hydro Generation, Year 1966–1990

	1966		1970		1975		1980		1985		1990	
	Billions kwh	%	Billions kwh	%	Billions kwh	%	Billions kwh	%	Billions kwh	%	Billions kwh	%
Thermal Generation:												
Coal	99.9	72.2	124.8	67.2	146.3	55.2	142.4	38.4	154.2	30.4	155.3	22.2
Gas	23.9	17.3	30.0	16.2	35.0	13.2	34.5	9.3	37.8	7.4	39.5	5.6
Oil	.9	.7	1.1	.6	1.3	.5	1.5	.4	1.7	.3	2.0	.3
Nuclear	1.4	1.0	17.5	9.4	69.5	26.2	178.4	48.2	300.1	59.1	489.1	69.7
Total	126.1	91.2	173.4	93.4	252.1	95.1	356.8	96.3	493.8	97.2	685.9	97.8
Hydro Generation:												
Conventional	12.1	8.8	12.1	6.6	12.8	4.9	13.6	3.7	14.3	2.8	15.5	2.2
Pumped Hydro	.1	....	.1	....	.1	....	.1	....	.1	....	.1	....
Total	12.2	8.8	12.2	6.6	12.9	4.9	13.7	3.7	14.4	2.8	15.6	2.2
Total Generation	138.3	100.0	185.6	100.0	265.0	100.0	370.5	100.0	508.2	100.0	701.5	100.0

TABLE B

West Central Region—Estimated Quantity of Coal, Oil and Gas Fuels Required for Electric Generation and Millions of Tons of Coal Equivalent

	1966		1970		1975		1980		1985		1990	
	Quantity [1]	Equiv. tons	Quantity [1]	Equiv. tons	Quantity [1]	Equiv. tons	Quantity [1]	Equiv. tons	Quantity [1]	Equiv. tons	Quantity [1]	Equiv. tons
Electric Generation:												
Coal	50.6	50.6	60.4	60.4	69.4	69.4	63.6	63.6	65.3	65.3	65.7	65.7
Gas	256.0	12.1	307.4	14.5	351.7	16.6	326.3	15.4	338.9	16.0	354.1	16.7
Oil	1.6	.5	1.9	.5	2.2	.6	2.4	.7	2.5	.7	3.0	.8
Nuclear		.7	....	8.5	....	32.9	....	79.7	....	127.0	....	207.0
Hydro		6.2	....	5.9	....	6.0	....	6.1	....	6.1	....	6.6
Total		70.1	....	89.8	....	125.5	....	165.5	....	215.1	....	296.8

[1] Fuel quantities in *millions* of tons of coal, barrels of oil and MCF of gas.

NOTE. Fuel quantities are based on kilowatthour generation by fuels and weighted average heat rates, respectively, and were computed using the following conversion factors: 10,750 Btu per pound of coal; 145,000 Btu per gallon and 42 gallons per barrel of oil; 1,015 Btu per cubic foot of gas. The oil and gas equivalents per ton of coal are 3.53 barrels of oil and 21.2 MCF of gas, respectively. The amount of electric generation produced by coal thermal generation increases from 1975 to 1990 but fuel requirements decrease due to the improvement in the weighted average heat rate. Fuel consumption by type of fuel in the West Central Region will vary from the quantities indicated for the period 1970–1990 based on the future level of the national economy, industrial growth in the region, air pollution abatement regulations, fuel transportation cost, the price relationship of various fuels, regulatory restrictions, and the quantities of energy interchanged with other regions.

TABLE 1

West Central Region—Coal Reserves

(In millions of short tons)

	Coal reserves January 1, 1960 [1]					Coal reserves January 1, 1968								Recoverable reserves Jan. 1, 1968 assuming 50 percent recovery
	Date of publication of estimate	Estimated original reserves				Date of publication of estimate	Estimated original reserves				Reserves depleted to January 1, 1968			
		Bituminous coal	Subbituminous coal	Lignite	Total		Bituminous coal	Subbituminous coal	Lignite	Total	Cumulative production	Prod. plus loss in mining	Remaining reserves	
Illinois	1953	[2] 137,329			137,329	1953	[4] 140,700			[4] 140,700	[7] 187	374	140,326	70,163
Iowa	1909	29,160			29,160	[5] 1965	7,237			7,237	361	722	6,515	3,257
Missouri	1913	79,362			79,362	[6] 1967	23,977			23,977	313	626	23,351	11,675
Nebraska	Trace quantities.					Trace quantities.								
Montana (Eastern Quarter) [3]	1949		40,100	128,820	[3] 168,920	1949		40,100	128,820	[3] 169,080	[8] 2	4	169,076	84,538
North Dakota	1953			350,910	350,910	1953			350,910	350,910	116	232	350,678	175,339
South Dakota	1952			2,033	2,033	1952			2,033	2,033			2,033	1,017
Wyoming (Northeast Corner) [3]	1950		47,444		[3] 47,444	1950			47,444	[3] 47,444	[8] 13	26	47,418	23,709
Minnesota & Wisconsin		0	0	0	0		0	0	0	0				
Total West Central Region					815,158					741,381	992	1,984	739,397	369,698
Total United States					1,719,964						[9] 3,785	7,570	[10] 1,575,412	787,706
West Central Region as Percent of Total U.S.					47.4									46.9

Remaining Coal Reserves January 1, 1968 by Rank and Sulfur Content [11]

Coal rank	Sulfur content, percent					Total remaining reserves
	1.0 or less	1.1–2.0	2.1–3.0	3.1–4.0	Over 4.0	
Bituminous:						
Illinois		[12] 1,656	23,869	94,963	19,838	140,326
Iowa				117	6,398	6,515
Missouri				8,220	15,131	23,351
Subbituminous Coal:						
Montana (Eastern Quarter)	40,100					40,100
Wyoming (Northeast Corner)	47,418					47,418
Lignite:						
Montana (Eastern Quarter)	128,976					128,976
North Dakota	319,096	31,582				350,678
South Dakota	2,033					2,033
Total	537,623	33,238	23,869	103,300	41,367	739,397
Percent of total	72.7	4.5	3.2	14.0	5.6	100.0

[1] Footnotes in detail appear in source material, "Coal Reserves of the United States—A Progress Report January 1, 1960" (Geological Survey Bulletin 1136).

[2] Remaining Reserves January 1, 1950.

[3] Remaining Reserves January 1, 1964 based on A. E. Ward Report of Fossil Fuels Missouri River Basin. The Reserves indicated are only for counties in FPC West Central Region.

[4] Remaining Reserves as of July 1, 1965.

[5] Coal Resources of Iowa by E. R. Landis & O. Van Eck, 1964.

[6] Coal Resources of Missouri by W. V. Searight, 1966.

[7] Production 1965 through 1967 only.

[8] Production 1964 through 1967 only.

[9] Production 1960 through 1967 only.

[10] Based on Remaining Reserves as of January 1, 1960 of 1,660,290 million tons less production and mining losses through 1967 and reduction of 55,385 and 21,923 million tons in Missouri and Iowa reserves respectively.

[11] "Sulfur Content of United States Coals" (U.S. Bureau of Mines Information Circular 8312, 1966).

[12] Low Sulfur Coal in Illinois by Jack A. Simon, Illinois Geological Survey, 1966.

NOTE. The present estimates of coal reserves are only provisional estimates and are subject to change as mapping, prospecting and development are continued. The amount of data available on the sulfur content of coal reserves in United States is inadequate for any realistic evaluations of "availability".

TABLE 2

West Central Region—Consumption of Coal for Electric Generation

	1961			1966			
	Consumption		Cost (cents) per million btu as burned	Consumption		Cost (cents) per million btu as burned	Average sulfur content, percent
	Coal tons	BTU (billions)		Coal tons	BTU (billions)		
Illinois	19, 991, 000	431, 746	24. 8	27, 599, 000	589, 984	23. 6	2. 8
Wisconsin	5, 076, 000	123, 195	31. 6	7, 605, 000	181, 159	29. 7	2. 4
Missouri	3, 737, 000	81, 358	22. 4	5, 837, 000	125, 350	22. 0	3. 5
Iowa	1, 922, 000	40, 128	27. 1	2, 841, 000	60, 366	27. 1	3. 7
Minnesota	2, 819, 000	62, 325	29. 9	4, 558, 000	101, 084	30. 9	2. 5
North Dakota	[1] 1, 140, 000	15, 681	27. 3	[1] 1, 946, 000	26, 722	[3] 14. 6	. 8
South Dakota	[1] 240, 000	3, 951	30. 0	[1] 218, 000	3, 777	30. 3	. 8
Nebraska	215, 000	5, 336	[2] 31. 4	418, 000	10, 234	30. 2	3. 7
Total West Central Region	35, 140, 000	763, 720	Avg. 26. 30	51, 022, 000	1, 098, 676	Avg. 25. 16	Avg. 2. 8

Increase in Coal Consumption for Generation in five year period 1961–1966 .... 45. 20%

Average Annual Increase in Coal Consumption for Generation 7. 73%

Decrease in Average As Burned Coal Cost in five year period 1961–1966 .... 4. 53%

Average Annual Decrease in As Burned Coal Cost. 0. 926%

[1] Lignite.

[2] 1961 price not available, therefore, 1962 price was used.

[3] Based on cost reported on 1,609,000 tons in West Central Region Fuel Survey.

SOURCE: National Coal Association, Steam-Electric Plant Factors 1961 & 1966. Federal Power Commission, Electric Power Statistics, monthly. U.S. Bureau of Mines Information Circular 8312, 1966.

The natural gas reserves in the West Central Region as of December 31, 1966 amounted to 1.33 trillion cubic feet or less than one percent of the total reserves in the United States. Based on the projected United States cumulative natural gas requirements for the period 1966 to 1990 of 680 trillion cubic feet the reported reserves of this region could supply only 0.20 percent of these requirements.

The oil consumption in the West Central Region represented less than one percent of the total fuel consumption for the region. The crude oil and natural gas liquid reserves in the region amount to 0.813 billion barrels or approximately 2 percent of the total liquid hydrocarbon reserves in the United States.

In the State of Illinois as of July 1, 1965, the latest revised estimates of coal remaining in the ground totaled 140,700 million tons in reserves, of which 63,900 million tons are classed as measured and indicated and 76,800 million tons as inferred, all of which is of bituminous rank. The reserves are well distributed over an area of 38,000 square miles or 67 percent of the State's area in 78 counties of the 102 counties in Illinois. The minimum thickness of coal considered in preparing this estimate was 28 inches, except for areas of strippable coal where an average thickness of 18 inches was used.

Coal seams in Illinois are at depths ranging from a few feet to several hundred feet below the surface. Ages ago, the coal bearing formations were downfolded into a huge spoon-shaped basin centered in the southeastern part of the State. As a result, the beds minable by underground methods lie at the center of the basin while along the outer rim in a total of 40 counties, approximately 19,000 million tons of strippable coal lie near enough to the surface to be recovered by strip mining.

Tonnage figures alone, however, cannot demonstrate the full importance of Illinois coal reserves. The thickness of the beds is also extremely important since this aspect has a bearing on mining methods and, therefore, productivity. Most of the remaining coal reserves are in coal beds thick enough to permit effective mechanical mining.

The estimated original coal reserves of Iowa total 7,236 million short tons, of which 3,500 million tons are classed as measured and indicated reserves and 3,735 million tons are classed as inferred. A total area of about 1,316,040 acres in 37 counties was included in the reserve calculations; an additional area of about 1,291,830 acres in 44 counties is indicated by the currently available information to be favorable for the presence of coal beds more than 14 inches thick. The total recorded coal production of Iowa through 1963 is about 356 million tons. Assuming that for each ton of coal produced another ton has been made unrecoverable, the remaining reserves of the State are about 6,524 million tons.

Past estimates of the coal resources of Iowa were highly generalized and were based solely on an assumed total area underlain by coal of potential economic interest and on an assumed average thickness of coal within that area. The estimate of Campbell and Parker (1909), the most frequently quoted, of 29,160 million tons included coal 14 inches or more thick in an area of 12,560 square miles. The present detailed estimate by Landis (1965) is smaller than the older generalized estimates and covers a much smaller area. This estimate of Iowa coal reserves is on a bed-by-bed original reserve basis. The ratio is about one-fourth as much reserves in about one-sixth as much area.

About one-third of Missouri is underlain by bituminous coal-bearing strata, and coal has been mined in 55 of the 63 counties in which it occurs. Coal deposits occur in an area of some 24,000 square miles extending northeastward across the State from Jasper County to Clark County. The estimated original coal reserves of Missouri total 23,977 million tons.

In the years since the Hinds (1912) estimate of 79,393 million tons was made, stratigraphic studies have indicated that many of his correlations of coal beds were in error and that the persistence in thickness which he assumed cannot be demonstrated in many localities. Coal beds thin and thicken from one area to another and in many instances in very short distances. An additional factor of considerable importance in the area north of the Missouri River is that glacial drift occupies the position of coal beds in many places. Details of this relationship can be established only by drilling or mining but, in general, considerable areas are affected.

A re-evaluation of Missouri's original (before mining) coal resources was made by Searight (1966) on a county-by-county basis. Current information does not support the large resources indicated by Hinds, and these have consequently been adjusted downward. In some cases, only 10 percent of the previous estimate has been retained, and others have been cut to as litttle as one percent of the earlier estimate. The total tonnage represented in the present estimate of 23,977 million tons is less than one-third that of 1912 estimate figures. The total cumulative tonnage mined in the period 1840 through 1967 has been approximately 313 million tons. The coal remaining is, therefore, estimated to be approximately 23,335 million tons.

The original coal reserves of Montana total 222,047 million tons as estimated by Combo and others (1949). This estimate includes 2,363 million tons of bituminous coal, 132,151 million tons of subbituminous coal, and 87,533 million tons of lignite. The reserves were estimated according to standard procedures of the U.S. Geological Survey with several minor exceptions as follows: for bituminous coal the thickness categories used were 14 to 24 inches, 24 to 36 inches, and more than 36 inches, instead of the standard categories of 14 to 28 inches, 28 to 42 inches, and more than 42 inches, which were established after the Montana work was underway. For subbituminous coal and lignite standard categories of 2½ to 5 feet, 5 to 10 feet, and more than 10 feet were used. The Montana coal fields cover 35 percent of the total area of the State. Reserves are present in 35 out of 56 counties, but are concentrated largely in the Fort Union region and the Powder River Basin in the eastern part of the State. Big Horn, Powder River, and Rosebud Counties alone contain more than half the total in the State. For the past several years considerable exploration has been conducted by mining and petroleum companies and currently (April 1967) revised estimates indicate the presence of deposits of strippable reserves totaling about 8 billion tons.

The original lignite reserves of North Dakota, as estimated by Brant (1953), total 350,910 million tons of which 9,522 million tons are classed as measured, 50,120 million tons as indicated, and 291,268 million tons as inferred. The reserves were estimated according to the standard procedures of the U.S. Geological Survey. All the lignite included in the estimate is less than 1,200 feet below the surface and about 70 percent of the total reserves are less than 500 feet below the surface.

The reserves are well distributed over an area of 28,000 square miles in 23 counties in the western

half of the State. Of several counties with large reserves, Dunn County is conspicuous in containing 71 billion tons or about one-fifth of the State total. This is also the record reserve tonnage for coal-bearing counties in the United States.

The original lignite reserves of South Dakota, as estimated by D. M. Brown (1952), total 2,033 million tons, all of which is less than 1,000 feet below the surface. The reserves were estimated according to standard procedures of the U.S. Geological Survey. The lignite reserves are concentrated in six counties in the northwestern part of the State. Harding County contains nearly 84 percent of the estimated reserves, but most of past production has been obtained from Dewey and Perkins Counties.

Inventory of Fossil Fuel Resources

During the period 1970–1990, electric generation will be dependent upon five basic forms of energy—coal, gas, oil, hydro, and nuclear. This report is concerned primarily with fossil fuels. The availability of approximately 370 billion tons of recoverable coal reserves in the West Central Region as shown in Figure 1 and listed in Table 1 are more than sufficient to meet the electric utilities' requirements through the year 2000. Coal, however, will be faced with continuing pressures from other forms of energy, and based on present trends the most significant competition will be from nuclear energy.

In determining the type of fuel to be used for electric generation a number of factors have to be reviewed and evaluated, each of which will have a bearing on total fuel costs for any one location. The cost of transportation, anti-air pollution devices, storing, handling and disposing of the fuel product are economic factors which can make a low cost fuel the most expensive fuel. Therefore, while a general picture can be drawn of the availability and price of fuels, the final determination in selecting a fuel or fuels for a particular plant must be based on the specific facts pertinent to that plant and its location.

During the past twenty years the coal industry has contributed a great deal to the stability of fuel prices. Mechanization of the mines has enabled the industry to either reduce or at least maintain within reasonable limits the price of its product, in spite of continuing increases of over-all price indexes. During the period 1970–1990 it is expected that there will be continuing improvement in the mechanization and handling of coal at the mine. Some of the new developments in underground mining in recent years have been the use of a mobile bridge conveyor which has increased the productivity from a continuous miner substantially, the underground push-button miner, the installation of long wall mining equipment, and the application of computer simulation techniques.

Although coal is available in sufficient quantities in the West Central Region to supply the entire energy requirements of the electric utilities in this region, competition will determine the extent to which coal will penetrate each market.

WEST CENTRAL REGION
COAL RESERVES

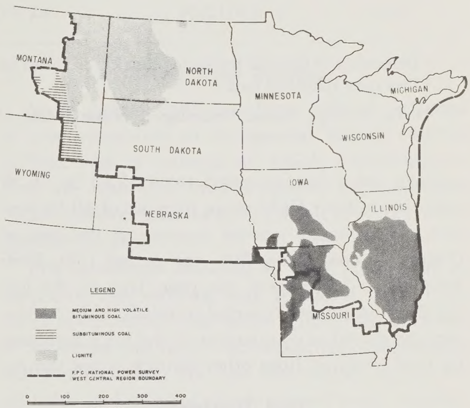

FIGURE 1

Coal Price F.O.B. Mine

A fossil fuel survey questionnaire was sent to twenty-six electric utilities which consume approximately 90 percent of the coal used for electric generation in the West Central Region. The questionnaire inquired as to producing district, tonnage burned, f.o.b. mine price, average BTU per lb. received, cents per million BTU f.o.b. mine, methods of transportation used, freight rate, haulage distance, and tonnage per shipment.

Table 3 compares the 1961 f.o.b. mine prices listed in the 1964 National Power Survey and the 1966 f.o.b. mine prices reported by the electric utilities in this region. Although coal was reported purchased from nine coal producing districts, on tonnage obtained from District 10 (36 million tons of 46 million tons reported in the survey) the

TABLE 3

West Central Region—Fossil Fuel Survey, Coal Consumption and F.O.B. Mine Price

Coal producing district [1]	Tonnage	Weighted average cents per million B.t.u. f.o.b. mine		% Increase in price
		1961 survey	1966 survey	
3	[2] 12, 141	16. 49	17. 39	
4	[2] 553, 460	15. 20	16. 39	
8	[2] 165, 681	14. 34	17. 96	
9	4, 412, 950	12. 56	15. 97	
10	36, 424, 000	15. 03	16. 56	10. 18
11	[2] 14, 774	15. 56	16. 14	
12	[2] 635, 000		19. 84	
15	2, 077, 000		19. 17	
21	1, 644, 000		12. 53	
Total	45, 939, 000			

[1] Definitions of the coal producing districts are listed on page III–2–41.
[2] Less than 1,000,000 tons.

NOTE. Average Annual Percentage Increase in Cost of District 10 Coal in Five Year Period 1961 to 1966, 1.92%/year

average price has increased from 15.03 to 16.56 cents per million BTU or an increase of 10.18 percent. The average annual increase in the cost of District 10 coal in the five year period 1961–1966 amounts to 1.9 percent per year. Due to the less significant tonnages reported in relationship to tonnage produced, a comparison of the price increases for coal obtained from other districts is not shown.

Fuel Transport

In the past, rail transportation has predominated in the movement of coal in this region, and within recent years the cost of coal transported by rail has been reduced substantially on selected movements of coal shipped by unit train.

Table 4 presents the type of transportation used for the 46 million tons reported in the survey. Of this total tonnage, approximately 10 million tons, or 21.8 percent were shipped by unit train, 12,200,000 tons, or 26.6 percent were shipped by rail-barge, and 5,280,000 tons, or 11.5 percent were shipped by rail-lake.

The present planned requirements of electric generating plants indicate that between 1970 and 1975 approximately 17,000,000 tons will be shipped by unit train or an increase of 7,000,000 tons. However, by 1975 coal transported by conveyor will increase from 2,000,000 tons to 9,000,000 tons, or an increase of 7,000,000 tons and coal transported by captive shuttle train will increase by 4,000,000 tons. During this period the amount of coal shipped by conveyor and captive shuttle train indicates an increase of 11,000,000 tons versus a 7,000,000 ton increase for unit train shipments.

TABLE 4

West Central Region—Fossil Fuel Survey, Coal Transportation Data

Type of shipment	Tonnage shipped	% of total tonnage shipped
Unit Train	10, 040, 000	21. 8
Train Lot	2, 060, 000	4. 5
Volume Rate	3, 795, 000	8. 3
Conventional Rail	2, 998, 000	6. 5
Barge	4, 127, 000	9. 0
Rail-Barge	12, 216, 000	26. 6
Rail-Lake	5, 278, 000	11. 5
Truck	3, 146, 000	6. 8
Conveyor	2, 144, 000	4. 7
Coal Pipeline		
Other	135, 000	0. 3
Total Tonnage	45, 939, 000	100. 0

Rail Transportation Cost

The average rail freight cost in the West Central Region for coal shipments in 1966 amounted to $1.97 per ton on a tonnage of 23,500,000 tons, or approximately 46 percent of the coal consumed in this region.

The unit train freight rates reported in the survey when compared on a basis which considers railroad ownership of all equipment indicates that the mills per ton mile range from 10.3 mills per ton mile for an 85 mile haul to 7.2 mills for a 138 mile haul and down to 5.0 mills for a 355 mile haul.

Figure 2 illustrates the curves shown on page 338, Part II of the 1964 National Power Survey prepared by the previous Fossil Fuel Committee and a plot of present unit train rates which indicates that mills per ton mile for shipments between 85 and 355 miles is slightly higher than rates projected at that time for 1980. It is interesting to note that the unit train rates reported are not less than 5.0 mills and the longest haul reported was 355 miles.

Past projections indicated that unit train freight rates could level out at a cost of 4 mills per ton mile for hauls between 350 miles and 600 miles. However, no hauls of 400 to 500 miles at 4 mills were reported.

A 4 mill per ton freight rate, when applied to coal that averages 11,500 BTU/lb., amounts to 7 cents per million BTU for a 400 mile haul and 8.7 cents per million BTU for a 500 mile haul. This freight cost added to an average f.o.b. mine price of 16.5 cents per million BTU for coal shipped from the District 10 (which represented approximately 72 percent of the coal consumed in the West Central Region) would result in an as-received cost of 23 to 25.2 cents per million BTU which is slightly above recent projected breakeven costs for nuclear energy.

The inability of the utilities to obtain a lower cost than 5 mills per ton mile is perhaps substantiated by the fact that as of the present date between now and 1975 approximately 10,000 megawatts of nuclear capacity is planned or considered for installation in the West Central Region.

Based on discussions with railroad representatives in this region, it is their judgment that the cost of rail transportation in the period 1980–1990 on unit train shipments of coal will be approximately 4 mills per ton mile on hauls greater than 300 miles, and some are optimistic that with improvements in rail technology the cost during this period will possibly be lower.

The railroads presently, however, are not concerned as much with the level of future rates but, based on the proposed stringent air pollution laws, whether or not there will be market for most of the coal in its present form.

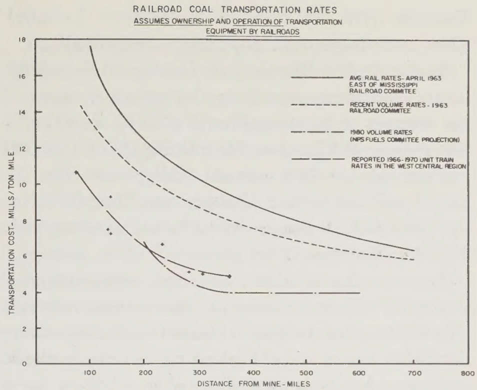

FIGURE 2

Illinois Coal Reserves[3]

As of July 1, 1965 the latest revised estimates of coal remaining in the ground totaled 140,700 million tons in reserves, of which 63,900 million tons are classed as measured and indicated and 76,800 million tons as inferred, all of which is of bituminous rank.

The minimum thickness of coal considered in preparing this estimate was 28 inches, except for areas of strippable coal where an average thickness of 18 inches was used. Coal underlying large towns was not included; nor was coal underlying known oil fields and areas of closely spaced rotary drilling, except for an area of Franklin County, where such drilling was done in close cooperation with active mining. About 90 percent of the estimated reserves is less than 1,000 feet below the surface; the remainder is between 1,000 and 1,200 feet below the surface.

The reserves are well distributed over an area of 38,000 square miles or 67 percent of the state's area in 78 counties of the 102 counties in Illinois and are listed by county in Table 6.

Lying within the Pennsylvanian System or "Coal Measures" of Illinois are perhaps 40 to 50 coal beds. These beds vary in thickness from thin streaks to more than 12 feet. About 20 of them have been mined in various parts of the state at one time or another during the past 85 years. At present, the Herrin (No. 6), Harrisburg (Springfield) (No. 5),

[3] Based on information and data obtained from Jack A. Simon, Geologist and Head of the Coal Section of the Ill. Geological Survey, 1967.

Danville (No. 7) and the Colchester (LaSalle) (No. 2) beds are most important commercially.

Studies by the Illinois State Geological Survey indicate that these same beds also constitute most of the reserves of the state; Herrin (No. 6) 63,000 million tons or 44.8 percent, Harrisburg (No. 5) 40,000 million tons or 28.6 percent, Colchester (No. 2) 18,200 million tons or 12.9 percent, Danville (No. 7) 7,800 million tons or 5.6 percent, all other beds 11,400 million tons or 8.1 percent.

Tonnage figures alone, however, cannot demonstrate the full importance of Illinois' coal reserves. The thickness of the beds is also extremely important since this aspect has a bearing on mining methods and, therefore, productivity.

Table 5 indicates that most of the remaining coal reserves are in coal beds thick enough to permit effective mechanical mining. Coal seams in Illinois are at depths ranging from a few feet to several hundred feet below the surface. Ages ago, the coal bearing formations were downfolded into a huge spoon-shaped basin centered in the southeastern part of the state. As a result, some beds at the center of the basin lie at depths in excess of 1,000 feet while along the outer rim approximately 19,000 million tons of strippable coal as listed in Table 7 by county, Table 8 by bed thickness and Table 9 classified by beds, lie near enough to the surface to be recovered by strip mining.

TABLE 5

Estimated Remaining Coal Reserves of Illinois as of January 1, 1968, by Thickness Category

(In millions of short tons)

Thickness of bed (inches)	Reserves measured, indicated and inferred
18 to 28	3, 500
28 to 36	25, 477
36 to 48	44, 003
48 to 72	45, 932
72 to 96	20, 250
More than 96	1, 163
Total	140, 325

In all calculations the coal was assumed to weigh 1,800 tons per acre-foot. Where data permitted, isopach lines were drawn on the coal beds at 28 inches, 42 inches and at succeeding 1 foot intervals; and reserves were calculated in each of these categories. Strippable reserves were based on a lower thickness limit of 18 inches, the average thickness values and isopach intervals used are the same as those used in the study of minable coal reserves of Illinois by Cady and others (1952).

TABLE 6

Estimated Illinois Coal Reserves by County [1]

(In millions of short tons)

County	Remaining coal reserves as of Jan. 1, 1968 [2]		Total reserves
	Class I [3] measured & indicated	Class II [3] inferred reserves	
Adams	272	347	619
Bond	1, 831	925	2, 756
Brown	267	118	385
Bureau	1, 124	875	1, 999
Cass	103	396	499
Champaign		182	182
Christian	2, 958	1, 898	4, 856
Calhoun	15		15
Clark	168	1, 051	1, 219
Clay		1, 619	1, 619
Clinton	1, 325	2, 463	3, 788
Coles	81	275	356
Crawford	443	1, 963	2, 406
Cumberland	4	333	337
DeWitt		174	174
Douglas	398	315	713
Edgar	1, 750	1, 242	2, 992
Edwards		1, 134	1, 134
Effingham		1, 786	1, 786
Fayette	1, 174	2, 056	3, 230
Franklin	3, 689	1, 314	5, 003
Fulton	1, 885	126	2, 011
Gallatin	1, 949	2, 019	3, 968
Greene	452	146	598
Grundy	384	445	829
Hamilton	2, 423	2, 341	4, 764
Hancock	29	1	30
Hardin		4	4
Henderson		53	53
Henry	435	463	898
Jackson	462	169	631
Jasper		3, 277	3, 277
Jefferson	1, 750	3, 020	4, 770
Jersey	129	150	279
Kankakee	82	19	101
Knox	1, 221	336	1, 557
LaSalle	1, 284	742	2, 026
Lawrence	894	2, 057	2, 951
Livingston	593	2, 386	2, 979
Logan	627	1, 962	2, 589
McDonough	353	231	584
McLean	421	795	1, 216
Macon	293	1, 559	1, 852

See footnotes at end of table.

TABLE 6—Continued

Estimated Illinois Coal Reserves by County [1]—Continued

(In millions of short tons)

County	Remaining coal reserves as of Jan. 1, 1968 [2]		Total reserves
	Class I [3] measured & indicated	Class II [3] inferred reserves	
Macoupin	3, 613	2, 854	6, 467
Madison	1, 791	796	2, 587
Marion	426	1, 539	1, 965
Marshall	399	806	1, 205
Mason		23	23
Menard	1, 327	750	2, 077
Mercer	48	23	71
Monroe	7	....	7
Montgomery	3, 927	1, 596	5, 523
Morgan	184	1, 376	1, 560
Moultrie	123	232	355
Peoria	1, 651	663	2, 314
Perry	1, 889	666	2, 555
Piatt		11	11
Pike	111	33	144
Putnam	589	155	744
Randolph	600	18	618
Richland		2, 124	2, 124
Rock Island	39	23	62
St. Clair	1, 725	1, 169	2, 894
Saline	3, 095	1, 157	4, 252
Sangamon	3, 009	2, 844	5, 853
Schuyler	634	78	712
Scott	171	55	226
Stark	239	279	518
Tazewell	102	224	326
Vermilion	1, 884	537	2, 421
Wabash	24	1, 164	1, 188
Warren	219	184	403
Washington	1, 560	2, 553	4, 113
Wayne		4, 050	4, 050
White	583	4, 092	4, 675
Will	20	....	20
Williamson	2, 033	1, 046	3, 079
Woodford	214	960	1, 174
Total	63, 504	76, 847	140, 351

[1] All reserves were calculated based on coal in beds more than 28 inches thick except strippable reserves were based on coal in beds more than 18 inches thick. About 90 percent of reserves are less than 1,000 feet below the surface; the remainder is between 1,000 and 1,200 feet below the surface.

[2] Based on Illinois Geological Survey: Bulletin 78 Minable Coal Reserves of Illinois by G. H. Cady and others, 1952. Circular 312 Subsurface Geology and Coal Resources of the Pennsylvanian System by K. E. Clegg, 1961. Strippable Coal Reserves of Illinois: Circular 228 (1957), Circular 260 (1958) & Circular 311 (1961) by William H. Smith. Circular 348 (1963) by William H. Smith and Dwain J. Berggen. Circular 374 (1964) by David L. Reinertsen. Information obtained from Jack A. Simon, Geologist and Head of the Coal Section of the Illinois State Geological Survey on coal reserve studies to be published in 1968. Annual Coal, Oil and Gas Reports of Illinois Department of Mines and Minerals 1950 through 1967.

[3] Class I is equivalent to proved Class I–A and probable Class I–B, Class II is equivalent to Class II–A strongly indicated and Class II–B weakly indicated categories for coal reserves compiled by G. H. Cady (1952). Class I is approximately equivalent to "measured and indicated" category and Class II is approximately equivalent to "inferred" category of the U.S. Geological Survey.

Iowa Coal Reserves [4]

The estimated original coal reserves of Iowa total 7,236.54 million short tons, of which 3,500.72 million tons is classed as measured and indicated reserves and 3,735.82 million tons is classed as inferred. A total area of about 1,316,040 acres in 37 counties was included in the reserve calculations; an additional area of about 1,291,830 acres in 44 counties is indicated by the currently available information to be favorable for the presence of coal beds more than 14 inches thick. The estimated original reserves are summarized by county in Table 11.

Also listed in Table 11 is the total area of the county underlain by coal included in estimated reserves and the additional area within each county that the available information indicates to be favorable for the presence of coal beds 14 inches or more thick. Reserves were estimated in 37 counties; 7 additional counties are listed in which no coal reserves could be estimated but which contained favorable areas.

The total recorded coal production of Iowa through 1963 is about 356.28 million tons. Assuming that for each ton of coal produced another ton has been made unrecoverable, the remaining reserves of the State are about 6,524 million tons. Again assuming 50 percent recoverability in the future, the recoverable reserves of Iowa, estimated and categorized by individual bed, are about 3,262 million tons.

The total area of Iowa underlain by rocks of Pennsylvanian age is variously cited as 24,250 square miles (Lees, 1927a, p. 74), 19,000 square miles (Hinds, 1909, p. 30), 20,000 square miles (Keyes, 1894, p. 33) and 23,100 square miles (Averitt, 1961, p. 58). An assumed area of about 20,000 square miles would appear to be a conservative estimate. The reserves estimated in the present study

[4] Landis E. R., and Van Eck O. J., 1965, Coal Resources of Iowa, Iowa Geol. Survey, Tech. Paper No. 4, p. 11–15.

TABLE 7

Estimated Illinois Strippable Coal Reserves by County[1]

(In thousands of short tons)

County	Remaining reserves as of Jan. 1, 1968[2] — Class I[3] measured and indicated, reserves at overburden thickness (ft.) 0–50	50–100	100–150	Total	Class II[3] inferred reserves, reserves at overburden thickness (ft.) 0–50	50–100	100–150	Total	Total, Class I & II
Adams	68,327	159,100	44,259	271,686	20,009	169,415	158,165	347,589	619,275
Brown	65,969	115,290	86,466	267,725	14,557	45,325	58,889	118,771	386,496
Bureau	45,695	94,214	92,107	[4] 232,016	19,258	73,578	125,288	218,124	450,140
Cass	6,922	40,958	55,301	103,181	6,025	35,103	100,594	141,722	244,903
Calhoun	4,422	4,759	5,834	15,015					15,015
Fulton	415,115	1,025,175	483,418	[4] 1,923,708	29,678	36,431	59,830	125,939	2,049,647
Gallatin	39,447	74,617	116,291	230,355		718	6,618	7,399	237,754
Greene	103,815	180,528	167,956	452,299	25,743	72,050	47,830	145,623	597,922
Grundy				[5] 350,000					350,000
Hancock	11,887	17,157		29,044	112	672		784	29,828
Henderson					3,991	48,963	157	53,111	53,111
Henry	92,617	161,412	116,318	[5] 435,347	4,031	103,228	79,659	186,918	622,265
Jackson	91,585	111,468	97,264	[4] 300,317	44,659	18,217	17,128	80,004	380,321
Jersey	35,842	46,413	46,760	129,015	26,085	31,313	34,048	91,446	220,461
Kankakee				[5] 27,000					27,000
Knox	432,356	585,484	211,897	1,229,737	34,833	137,451	164,178	336,462	1,566,199
LaSalle				[5] 220,000				[5] 60,000	280,000
Livingston				[5] 45,000				[5] 5,000	50,000
McDonough	111,851	238,568	2,392	352,811	27,900	149,063	54,546	231,509	584,320
Macoupin	36,967	66,562	100,712	204,241	246	19,835	51,283	71,364	275,605
Madison	68,354	217,838	223,028	509,220	3,228	30,887	72,015	106,130	615,350
Marshall	9,276	18,484	88,263	116,023					116,023
Mercer	1,328	2,102	387	[5] 58,817	3,206	7,959		11,165	69,982
Monroe	6,726			6,726					6,726
Peoria	355,735	720,882	571,208	1,647,825	43,358	202,781	277,412	523,551	2,171,376
Perry	138,949	597,738	281,110	[4] 1,017,797		13,182	14,662	27,844	1,045,641
Pike	43,678	42,623	24,885	111,186	7,567	13,782	11,866	33,215	144,401
Randolph	81,661	178,456	158,339	[4] 418,456	196	6,283	8,934	15,413	433,869
Rock Island				[5] 40,000					40,000
St. Clair	80,269	387,646	738,318	[4] 1,206,233					1,206,233
Saline	81,012	175,498	263,047	[4] 519,557			3,873	3,873	523,430
Schuyler	250,760	288,656	96,788	[4] 636,204	18,644	19,337	40,279	78,260	714,464
Scott	16,864	106,477	48,201	171,542		6,221	48,846	55,067	226,609
Stark	42,463	156,092	43,089	[4] 241,644	28,030	114,971	136,666	279,667	521,311
Tazewell	9,460	31,251	61,471	102,182	140	16,394	31,289	47,823	150,005
Warren	75,461	94,469	9,064	[5] 218,994	29,287	130,492	24,892	184,671	403,665
Will				[5] 20,000					20,000
Williamson	114,532	188,705	289,515	592,752	3,565	8,542	8,811	20,918	613,670
Vermilion & Edgar	219,551	268,858	197,609	[5] 686,018	62,908	99,019	61,782	223,709	909,727
Subtotal of 40 Counties	3,158,896	6,397,480	4,721,297	[6] 15,139,673	457,256	1,611,212	1,696,613	[7] 3,833,071	[8][9] 18,972,744
Possible Strippable Reserves in 35 Other Counties									[10] 2,000,000
Total									20,972,744

[1] Strippable coal is defined as coal 18 or more inches in thickness that has an overburden thickness of up to 150 feet.

[2] Based on Illinois Geological Survey: Strippable Coal Reserves of Illinois, Circular 228 (1957), Circular 260 (1958) & Circular 311 (1961) by William H. Smith. Circular 348 (1963) by William H. Smith and Dwain J. Berggen. Circular 374 (1964) by David L. Reinertsen. Annual Coal, Oil and Gas Reports of Illinois Department of Mines and Mineral 1956 through 1967.

[3] Class I is equivalent to proved Class I-A and probable Class I-B, Class II is equivalent to Class II-A strongly indicated and Class II-B weakly indicated categories for coal reserves compiled by G. H. Cady (1952). Class I is approximately equivalent to "measured and indicated" category and Class II is approximately equivalent to "inferred" category of th U.S. Geological Survey.

[4] Remaining coal reserves based on strip mining production and 80 percent recoverability factor from mined out dates used in surveys.

[5] Includes or indicates strippable coal reserves in surveys that will be published in detail in late 1968.

[6] 862,000 M Tons. Includes strippable reserves in surveys to be published in detail in late 1968.

[7] 65,000 M Tons. Includes strippable reserves in surveys to be published in detail in late 1968.

[8] 927,000 M Tons. Includes strippable reserves in surveys to be published in detail in late 1968.

[9] Equivalent to strippable reserves of 19,271,504 M tons reported in other summaries less production and mining losses of 298,760 M tons.

[10] Based on estimate by William H. Smith.

TABLE 8

Summary of Estimated Remaining Illinois Strippable Coal Reserves by Average Thickness[1]

[In thousands of tons]

Average thickness of coal	Class I reserves at overburden depths (ft.) 0–50	50–100	100–150	Total	Class II reserves at overburden depths (ft.) 0–50	50–100	100–150	Total	Total I & II
Inches:									
18	227, 597	307, 968	105, 878	641, 443	43, 936	66, 028	46, 257	156, 221	797, 664
24	453, 754	861, 763	408, 156	1, 723, 673	163, 818	578, 589	533, 052	1, 275, 459	2, 999, 132
30	874, 615	1, 708, 437	1, 029, 950	3, 613, 002	94, 529	527, 219	717, 827	1, 339, 575	4, 952, 577
36	154, 425	316, 680	331, 874	802, 979	32, 352	274, 812	251, 304	558, 468	1, 361, 447
42	258, 625	321, 941	145, 212	725, 778	2, 903	22, 128	5, 846	30, 877	756, 655
48	421, 974	1, 002, 395	813, 274	2, 237, 583	39, 862	280, 733	373, 590	694, 185	2, 931, 768
54	228, 393	645, 450	382, 889	1, 256, 732	1, 110	17, 403	11, 854	30, 367	1, 287, 099
60	273, 732	431, 453	363, 631	1, 068, 816	9, 584	11, 321	6, 670	27, 575	1, 096, 391
72	271, 937	629, 992	444, 432	1, 346, 361		12, 173	33, 763	45, 936	1, 392, 297
84	70, 775	405, 512	645, 155	1, 121, 442					1, 121, 442
96	46, 655	125, 357	235, 088	407, 100					407, 100
Total	3, 282, 422	6, 756, 948	4, 905, 539	14, 944, 909	388, 094	1, 790, 406	1, 980, 163	4, 158, 663	19, 103, 572

[1] Summary of Illinois Geological Survey Circulars 228, 260, 311, 348, 374, and two unpublished reports. Parts 1, 2, 3, 4, 5, 5A, 6, of eight part series.

Source: Illinois Geological Survey, William H Smith.

TABLE 9

Summary of Estimated Remaining Illinois Strippable Coal Reserves by Coal, Overburden Thickness, and Reliability[2]

[In thousands of tons]

Coal bed name	Class I reserves at overburden depths (ft). 0–50	50–100	100–150	Total	Class II reserves at overburden depths (ft.) 0–50	50–100	100–150	Total	Total I & II
Danville (No. 7)	219, 551	268, 858	197, 609	686, 018	62, 908	99, 019	61, 782	223, 709	909, 727
Herrin (No. 6)	1, 091, 418	2, 737, 944	2, 388, 035	6, 217, 397	38, 628	499, 406	644, 342	1, 231, 136	7, 448, 533
Harrisburg (No. 5)	619, 785	1, 224, 920	848, 732	2, 693, 437	66, 307	214, 813	201, 106	482, 226	3, 175, 663
Colchester (No. 2	1, 194, 082	2, 378, 699	1, 420, 488	4, 993, 269	205, 103	932, 413	1, 065, 977	2, 203, 493	7, 196, 762
Miscellaneous Coals	92, 193	80, 938	57, 040	230, 171	48, 224	26, 759	29, 812	104, 795	334, 966
Rock Island (No. 1)	69, 489	83, 261	53, 037	205, 787					205, 787
Total	3, 286, 518	6, 774, 620	4, 964, 941	15, 026, 079	421, 170	1, 772, 410	2, 003, 019	4, 245, 359	19, 271, 438

[1] Summary of Illinois Geological Survey Circulars 228, 260, 311, 348, and two unpublished reports. Parts 1, 2, 3, 4, 5, 5A, 6, of eight part series.

Source: Illinois Geological Survey, William H. Smith.

are within an area of 1,316,040 acres or about 2,056 square miles, and an additional area of about 1,291,830 acres or about 2,018 square miles possibly are underlain by coal. Therefore, reserves were estimated in about 10 percent of the area underlain by Pennsylvanian rocks and an additional 10 percent is indicated by the currently available information to be favorable for the presence of resources of potential economic interest. Certainly the total coal resources of Iowa are much larger than the known resources, or reserves, that can be estimated and categorized on an individual-bed basis. It seems reasonable to assume that the amounts of coal may be nearly equal in the area in which reserves were estimated, in the area outlined as favorable for potential coal resources, and in the remainder of the area (80 percent of the total) underlain by coal-bearing Pennsylvanian rocks. On the basis of these assumptions, the total potential original coal resources of Iowa are estimated to be about 21,000 million tons.

No detailed estimate of Iowa coal reserves on a bed-by-bed original reserve basis has been previously made. Past estimates of the coal resources of Iowa were highly generalized and were based solely on an assumed total area underlain by coal of potential economic interest and on an assumed average thickness of coal within that area. The esti-

Comparison of Past and Present Estimates

Author	Area included in estimate (square miles)	Estimated original reserves (millions of short tons)
Campbell and Parker (1909). .	12, 560	29, 160
Lees (1927a).	12, 750	29, 950
This report (1963); individual bed estimate.	2, 056	7, 236. 54
Total potential resource estimate.	20, 000	21, 000

mate of Campbell and Parker (1909), the most frequently quoted, included coal 14 inches or more thick in an area of 12,560 square miles. They mentioned an additional area of 5,640 square miles of possible coal but apparently they did not include it in their estimate. The estimate of Lees (1927a, p. 74) covers 11,250 square miles of "Des Moines beds which are not covered by Missouri or Cretaceous strata." Lees used an assumed average thickness of 4 feet of coal which he believed would give a content of 4,000 tons of coal per acre, or a total of 28,800 million tons. In addition Lees estimated that about 1,500 square miles is underlain by the Nodaway coal bed having an average thickness of 1.2 feet. The estimated 1,150 million tons in the Nodaway bed plus the 28,800 million tons gave an overall total of 29,950 million tons. As Lees' assumed weight of coal seems much too small by present standards, he may have been applying a recoverability factor not stated.

The present detailed estimate is smaller than the older generalized estimates and covers a much smaller area. The ratio is about one-fourth as much reserves in about one-sixth as much area. The very generalized estimate of total potential coal resources of Iowa, discussed earlier in this report, may be more directly comparable to the older reserves estimates of Campbell and Parker and of Lees because it attempts to estimate the total amount of coal of potential economic interest in the part of Iowa underlain by rocks that are known to be coal bearing. The estimated total potential original coal resources of about 21,000 million tons are less than the earlier estimates, but the figure is derived by extension of the detailed bed-by-bed reserve estimate and may, therefore, represent a more realistic appraisal of the total known and undiscovered coal resources of Iowa.

TABLE 10

Estimated Original Coal Reserves of Iowa, by Thickness Category

(In millions of short tons)

Thickness of bed (inches)	Reserves		
	Measured & indicated	Inferred	Total
14 to 28.	618	1, 542	2, 160
28 to 42.	1, 037	1, 216	2, 253
More than 42.	1, 846	978	2, 824
Total.	3, 501	3, 736	7, 237

Missouri Coal Reserves [5]

About one-third of Missouri is underlain by bituminous coal-bearing strata, and coal has been mined in 55 of the 63 counties in which it occurs. Coal deposits occur in an area of some 24,000 square miles extending northeastward across the State from Jasper County to Clark County. The estimated original coal reserves of Missouri total 23,977 million tons. The coal is in more than 40 different coal beds, all associated with rocks of Pennsylvanian age. Some of these are very persistent and crop out over large areas, whereas others are restricted or patchy in areas.

Numerous publications of the Missouri Geological Survey and of the U.S. Geological Survey deal extensively with the geology of Missouri coal. Two reports, both the result of cooperative work of the Missouri Geological Survey (then the Missouri Bureau of Geology and Mines) and the U.S. Geological Survey are very important to anyone interested in Missouri coal. The first of these is "The Coal Deposits of Missouri" by Henry Hinds (Hinds, 1912) and the second, "The Stratigraphy of the Pennsylvanian of Missouri" by Henry Hinds and F. C. Greene (Hinds and Greene, 1915). These two works discuss and describe the coal beds, character, stratigraphy, depth, and mining methods of that time. The coal resources of each county are treated with remarkable completeness. Estimates were made of the original tonnage in each county.

Coal Resources. Since the settlement of the State, the coal resources of Missouri have been known to be very large. In 1873, Broadhead estimated that

[5] Searight, Walter V., Mineral Fuel Resources, Coal, Mineral and Water Resources of Missouri Vol. XLIII Second Series 1967 Report of U.S. Geol. Survey and Missouri Geol. Survey p. 235–243.

TABLE 11

Original Coal Reserves (in Millions of Short Tons) of Iowa,[1] by County and Reserve Class and Areas (in Acres) Included and Omitted in Reserve Estimate

County	Measured and indicated reserves	Inferred reserves	Total reserves	Area of reserve estimate	Favorable area
Adair	2. 11	7. 12	9. 23	2, 350	14, 390
Adams	34. 81	86. 50	121. 31	53, 780	32, 020
Appanoose	196. 88	483. 33	680. 21	166, 630	28, 240
Boone	158. 81	84. 98	243. 79	39, 470	15, 950
Calhoun					16, 300
Carroll					12, 430
Cass	0. 37	2. 79	3. 16	10, 800	7, 480
Clarke		0. 42	0. 42	80	6, 740
Dallas	70. 49	79. 09	149. 58	26, 760	14, 720
Davis	40. 96	72. 75	113. 71	13, 430	11, 000
Decatur	39. 88	172. 48	212. 36	23, 360	57, 870
Fremont	1. 33	10. 00	11. 33	4, 650	41, 070
Greene	16. 81	29. 69	46. 50	9, 270	10, 870
Guthrie	33. 37	41. 00	74. 37	20, 300	28, 470
Hamilton	13. 30	24. 72	38. 02	6, 780	9, 970
Hardin	5. 00	6. 75	11. 75	1, 840	
Henry	1. 48	2. 15	3. 63	620	340
Jasper	102. 51	91. 81	194. 32	30, 820	15, 970
Jefferson	52. 48	74. 49	126. 97	22, 630	29, 880
Keokuk	77. 54	63. 08	140. 62	16, 220	6, 800
Lee	4. 88	11. 38	16. 26	4, 490	1, 770
Lucas	186. 31	296. 42	482. 73	80, 020	33, 940
Madison					23, 510
Mahaska	335. 24	188. 74	523. 98	68, 540	23, 710
Marion	443. 31	201. 85	645. 16	104, 170	28, 020
Marshall	4. 15	14. 91	19. 06	3, 430	2, 490
Mills					6, 250
Monroe	540. 51	344. 32	884. 83	129, 270	33, 800
Montgomery	0. 78	20. 21	20. 99	9, 620	162, 100
Muscatine	1. 03	2. 95	3. 98	1, 680	420
Page	25. 98	91. 14	117. 12	49, 220	286, 650
Polk	572. 18	177. 68	749. 86	92, 960	14, 760
Pottawattamie					10, 880
Poweshiek	0. 25	0. 47	0. 72	280	2, 550
Ringgold					4, 740
Scott	2. 89	3. 90	6. 79	1, 700	1, 270
Story	37. 83	82. 68	120. 51	16, 570	48, 590
Taylor	10. 63	41. 64	52. 27	19, 360	55, 850
Union					43, 170
Van Buren	53. 14	74. 73	127. 87	22, 610	16, 610
Wapello	165. 01	199. 34	364. 35	59, 460	27, 860
Warren	149. 97	281. 15	431. 12	89, 010	60, 260
Wayne	51. 91	299. 66	351. 57	97, 690	24, 660
Webster	66. 59	69. 50	136. 09	16, 170	17, 460
Total	3, 500. 72	3, 735. 82	7, 236. 54	1, 316, 040	1, 291, 830

[1] Landis op. cit. (footnote 2) p. 12–13.

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coal more than 18 inches thick within 200 feet of the surface is present under an area of about 7,000 square miles. Based on these figures, the minimum tonnage is 12,090 million tons of coal. In 1912, Hinds estimated the original resources of coal more than 14 inches thick to be 79,393 million tons.

In the years since the Hinds estimate was made, stratigraphic studies have indicated that many of his correlations of coal beds were in error and that the persistence in thickness which he assumed cannot be demonstrated in many localities. These factors are of particular significance for coal beds from which important tonnages of coal are being or have been mined. For example, the "Rich Hill" (Mineral) is not the Bevier coal and is not continuous with it, nor is it the "Bevier" (Croweburg) of Johnson County. The "Fort Scot Red" (Mulky) is not the same coal as the Lexington, nor is the Tebo the "Tebo" of north Missouri. Coal beds thin and thicken from one area to another and in many instances in very short distances. An additional factor of considerable importance in the area north of the Missouri River is that glacial drift occupies the position of coal beds in many places. Details of this relationship can be established only by drilling or mining but, in general, considerable areas are affected.

A re-evaluation of Missouri's original (before mining) coal resources is presented on a county-by-county basis in Table 13. These estimates take into consideration the changes necessitated by corrections in coal bed identification, increased data on thicknesses of the principal coal beds, and other factors. The estimates of 1912 are presented also for comparison with current estimates. In reviewing the coal resources of certain counties, it was found that little additional data were available beyond those used by Hinds in 1912. In many counties, however, current information does not support the large resources indicated by Hinds and these have consequently been adjusted downward. In some cases, only 10 percent of the previous estimate has been retained, and others have been cut to as little as 1 percent of the earlier estimate. The total tonnage represented in the current estimate is 23,977 million tons, less than one-third that of 1912 but approximately double that based on Broadhead's figures.

In order to arrive at an estimate of existing coal resources in the State, the estimated original tonnage present must be reduced by the amount that has been removed by mining plus the amount lost and wasted in mining (estimated to be about equal to the amount mined). The total cumulative tonnage mined in the period 1840 through 1967 has been approximately 313 million tons. The coal remaining is, therefore, estimated to be approximately 23,335 million tons. Of this, it is considered that approximately 10,500 million tons or 45 percent is thin (14 to 28 inches thick), 9,334 million tons or 40 percent of medium thickness (28 to 42 inches), and 3,500 million tons or 15 percent is thick (more than 42 inches).

It is probable that only that part of those coal resources which can be mined by large-scale surface methods will be recovered within the next 25 to 30 years. The greater part of such resources have already been explored and evaluated by major coal operators. They probably include most if not all of the resources which can be currently classified as measured resources. Because most of the currently pertinent exploration in Missouri has been done by only two companies, reserve information cannot be revealed. On the basis of projected needs of power plants now in operation or committed to construction, however, it is estimated that reserves of strippable coal amounting to not less than 85 to 100 million tons are present in Missouri.

TABLE 12

Estimated Coal Reserves of Missouri

[In millions of short tons]

Thickness of bed (inches)	Remaining coal reserves as of January 1, 1968 — Measured, indicated & inferred reserves
14 to 28	10, 500
28 to 42	9, 334
More than 42	3, 500
Total	23, 334

TABLE 13

Estimated Original Coal Resources of Missouri by County [1]

[In millions of short tons]

County	Hinds (1912)	Searight (1966)
Adair	2, 263. 6	900. 1
Andrew	1, 209. 6	12. 1
Atchison	411. 8	41. 2
Audrain	1, 320. 0	207. 3

See footnote at end of table.

TABLE 13—Continued

Estimated Original Coal Resources of Missouri by County [1]—Continued

County	Hinds (1912)	Searight (1966)
Barton	464. 3	150. 0
Bates	3, 989. 8	2, 311. 7
Boone	846. 7	500. 0
Buchanan	4, 203. 4	4. 2
Caldwell	1, 260. 4	12. 6
Callaway	450. 9	188. 2
Carroll	1, 000. 0	56. 2
Cass	2, 460. 7	24. 6
Cedar	170. 3	40. 0
Chariton	2, 168. 0	21. 7
Clark	200. 0	2. 0
Clay	1, 953. 6	19. 5
Clinton	1, 521. 2	15. 2
Cooper	31. 5	2. 2
Dade	33. 9	14. 0
Daviess	2, 752. 7	27. 5
De Kalb	1, 209. 6	12. 0
Gentry	1, 280. 5	12. 8
Grundy	1, 417. 0	354. 2
Harrison	3, 363. 8	1, 681. 9
Henry	1, 832. 7	832. 7
Holt	823. 2	8. 2
Howard	1, 280. 7	394. 4
Jackson	2, 097. 8	699. 3
Jasper	100. 0	93. 6
Johnson	5, 460. 0	1, 240. 0
Lafayette	877. 4	559. 9
Lewis	....	0. 1
Linn	2, 190. 1	269. 6
Livingston	1, 532. 2	153. 2
Macon	2, 985. 9	1, 985. 9
Mercer	4, 329. 6	2, 956. 8
Monroe	288. 5	207. 4
Montgomery	315. 6	311. 0
Nodaway	914. 7	10. 0
Pettis	300. 0	30. 0
Platte	3, 385. 0	3. 4
Putnam	4, 296. 2	[2] 2, 142. 0
Ralls	44. 0	82. 9
Randolph	2, 020. 7	1, 522. 6
Ray	1, 098. 2	616. 1
St. Clair	602. 1	602. 9
St. Louis	70. 8	....
Saline	337. 1	112. 1
Schuyler	337. 9	136. 3
Scotland	20. 0	2. 0
Sullivan	2, 971. 1	1, 125. 0
Vernon	1, 257. 4	1, 257. 4
Worth	1, 140. 5	11. 4
Other Counties	500. 0	....
Total	79, 392. 7	23, 977. 4

[1] Searight, op. cit. (footnote 4).

[2] Estimated by R. J. Gentile (1965).

Montana Coal Reserves [6]

The original coal reserves of Montana total 222,047 million tons as estimated by Combo and others (1949). This estimate includes 2,363 million tons of bituminous coal, 132,151 million tons of subbituminous coal, and 87,533 million tons of lignite. The area distribution of coal of various ranks in Montana is shown on a map by Combo and others (1950).

The Montana reserves were calculated and classified according to standard U.S. Geological Survey procedures and definitions with several minor exceptions as follows:

For bituminous coal the thickness categories used were 14 to 24 inches, 24 to 36 inches, and more than 36 inches, instead of the standard categories of 14 to 28 inches, 28 to 42 inches, and more than 42 inches, which were established after the Montana work was underway. For subbituminous coal and lignite coal standard categories of 2½ to 5 feet, 5 to 10 feet, and more than 10 feet were used.

The categories of measured and indicated reserves were combined in a single category termed "measured and indicated" because only a very small part of Montana reserves could be classed as measured. All coal classed as "measured and indicated" is less than 2 miles from the outcrop, and more than 50 percent is less than 1 mile. The standard category of inferred reserves includes most of the coal lying more than 2 miles from the outcrops.

The Montana estimate includes reserves only to a maximum depth of 2,000 feet below the surface and thus is more conservative than other State estimates, which generally include coal to a depth of 3,000 feet. No attempt was made to estimate reserves in intermediate categories, but about 75 percent of the total is less than 1,000 feet below the surface.

The Montana coal fields cover 35 percent of the total area of the State. Reserves are present in 35 out of 56 counties, but are concentrated largely in the Fort Union region and the Powder River Basin in the eastern part of the State. Big Horn, Powder River, and Rosebud Counties alone contain more than half the total in the State.

About 10 percent of the total area of coal-bearing rocks in Montana was not included in the estimate because no information was available on the thick-

[6] Averitt, Paul, 1960 Coal Resources of the United States (A progress report January 1, 1960) U.S. Geol. Survey Bulletin 1136 (1961) p. 64–66.

ness and extent of the beds. The areas omitted are concentrated, in general, in the northeastern lignite-bearing part of the State, where the coal-bearing rocks are concealed by glacial drift. The estimated reserves of lignite should be increased in the future as more detailed work is carried on in these areas.

Table 14 shows the estimated original coal reserves of Montana classified according to various reserve categories.

For the past several years considerable exploration has been conducted by mining and petroleum companies, the Northern Pacific Railway Company and Great Northern Railway Company, Montana-Dakota Utilities Company, Montana Power Company, Pacific Power & Light Company and the Montana Bureau of Mines and Geology Reports relating to most of this recent exploration activity have not as yet been published, however, the strippable reserve picture is constantly improving. All of the known Montana strippable deposits are in the Fort Union region, where currently (April 1967) revised estimates indicate the presence of deposits totaling about 8 billion tons. Considering that thousands of acres are under lease and that exploration and evaluation moved into high gear in the 1967 season, there is speculation that Montana may add still another 2 billion tons to strippable coal reserves estimates within the next three years.[7]

[7] Groff S. L., 1967, Montana's Place In The Nation's Coal Energy Picture, Montana Bureau of Mines and Geol., p. 8.

TABLE 14

Estimated Original Coal Reserves of Montana

[In millions of short tons]

Overburden (feet)	Thickness of bed (inches)	Reserves: Measured & indicated	Inferred	Unclassified	Total
Bituminous Coal:					
0 to 2,000	14 to 24	279	167	...	446
	24 to 36	348	144	...	492
	>36	1,036	389	...	1,425
		1,663	700	...	2,363
Subbituminous Coal:	*Thickness (ft)*				
0 to 2,000	2½ to 5	5,392	2,326	...	7,718
	5 to 10	15,486	9,246	...	24,732
	>10	26,370	15,975	...	42,345
	Unclassified			57,356	57,356
		47,248	27,547	57,356	132,151
Lignite:	*Thickness (ft)*				
0 to 2,000	2½ to 5	4,876	10,178	...	15,054
	5 to 10	6,613	13,136	...	19,749
	>10	2,566	435	...	3,001
	Unclassified			49,729	49,729
		14,055	23,749	49,729	87,533
Total, all ranks		62,966	51,996	107,085	222,047

TABLE 15

Estimated Lignite and Subbituminous Reserves of Montana (Eastern Quarter) by Counties in the West Central Region [1]

(In millions of short tons—Remaining reserves as of January 1, 1968)

County	Measured, indicated and inferred reserves		
	Lignite	Subbituminous	Total reserves
Carter	460		460
Custer	4, 860		4, 860
Daniels	3, 960		3, 960
Dawson	11, 100		11, 100
Fallon	2, 500		2, 500
McCone	24, 800		24, 800
Powder River	42, 000		42, 000
Prairie	1, 600		1, 600
Richland	21, 000		21, 000
Roosevelt	4, 100		4, 100
Rosebud		38, 800	38, 800
Sheridan	5, 600		5, 600
Treasure		1, 300	1, 300
Wibaux	7, 000		7, 000
Total	128, 980	40, 100	169, 080

[1] West Central Region only. Based on U.S. Bureau of Mines paper Fossil Fuels and Their Estimated Costs in the Missour River Basin by Albert E. Ward, Mining Engineer, Bureau of Mines, Denver, Colo.

TABLE 16

Estimated Lignite Reserves of Wyoming (Northeast Corner) by Counties in the West Central Region [1]

(In millions of short tons—Remaining lignite reserves as of January 1, 1968)

County	Measured, indicated & inferred reserves
Campbell	47, 400
Crook	4
Weston	40
Total	47, 444

[1] West Central Region only. Based on U.S. Bureau of Mines paper Fossil Fuels and Their Estimated Costs in the Missouri River Basin by Albert E. Ward, Mining Engineer, Bureau of Mines, Denver, Colo.

North Dakota Coal Reserves [8]

As estimated by Brant (1953), the original reserves of lignite in North Dakota total 350,910 million tons, of which 9,522 million tons are classed as measured, 50,120 million tons as indicated, and 291,268 million tons as inferred.

The reserves are well distributed over an area of 28,000 square miles in 23 counties in the western half of the State. Of several counties with large reserves, Dunn County is conspicuous in containing 71 billion tons, or about one-fifth of the State total. This is also the record reserve tonnage for coal-bearing counties in the United States.

All the lignite included in the estimate is less than 1,200 feet below the surface, and for this reason no categories of overburden were established. Brant (1953, p. 4) estimates that about 70 percent of the total reserves is less than 500 feet below the surface; about 28 percent is 500 to 1,000 feet; and only about 2 percent is between 1,000 and 1,200 feet.

The information available in preparing this estimate was limited almost entirely to data obtained at the outcrops of the beds but was supplemented locally by a few drill logs. In many unmapped areas information was available only for the thickest or best known bed. Of the 28,000 square mile area considered to be underlain by lignite beds more than 2½ feet thick, about 1.7 percent was omitted for lack of information.

The North Dakota reserves were estimated according to the standard procedures of the U.S. Geological Survey as previously defined, and the results are tabulated in the Brant report by individual beds and townships, and by various reserve categories. A summary of this information is presented in Table 17.

[8] Averitt, op. cit. (footnote 6) p. 69.

TABLE 17

Estimated Original Reserves of Lignite in North Dakota [1]

(In millions of short tons)

Thickness of bed (feet)	Reserves			Total
	Measured	Indicated	Inferred	
2½ to 5	3, 095	20, 095	224, 180	247, 370
5 to 10	3, 964	18, 627	36, 938	59, 529
>10	2, 463	11, 398	30, 150	44, 011
Total	9, 522	50, 120	291, 268	350, 910

[1] All beds are less than 1,200 ft. below the surface.

TABLE 18

Estimated Lignite Reserves of North Dakota by County [1]

[In millions of short tons]

County	Remaining lignite reserves as of January 1, 1968—Measured, indicated & inferred reserves
Adams	1, 800
Billings	17, 600
Bowman	6, 800
Dunn	71, 000
Golden Valley	8, 200
Grant	4, 600
Hettinger	12, 600
McKenzie	32, 000
McLean	16, 400
Mercer	30, 000
Morton	15, 200
Mountrail	15, 200
Oliver	17, 800
Sheridan	660
Slope	20, 000
Stark	24, 000
Williams	26, 000
6 Other Counties	30, 820
Total	350, 680

[1] Ward, op. cit. (footnote 8).

South Dakota Coal Reserves [9]

As estimated by D. M. Brown (1952), the original lignite reserves of South Dakota total 2,033 million tons, all of which is less than 1,000 feet below the surface. In addition, the State contains 10,900 tons of bituminous coal, but this amount is too small to show in the accompanying table. The reserves were calculated and tabulated according to standard U.S. Geological Survey procedures and definitions.

As recorded in the report by Brown, the lignite reserves are concentrated in six counties in the northwestern part of the State. Harding County contains nearly 84 percent of the estimated reserves, but most of past production has been obtained from Dewey and Perkins Counties.

The accompanying table shows the estimated original reserves of lignite in South Dakota classified by thickness of bed and by the measured, indicated, and inferred categories.

Natural Gas Consumption, Price and Reserves

The consumption and average cost of natural gas for electric generation in the West Central Region is listed by states in Table 22. During the five year period 1961–1966 the consumption of gas for thermal electric generation increased from 0.223 to 0.260 trillion cubic feet or at an average annual rate of 3.11 percent compared to a 7.73 percent average annual increase in coal consumption in the same period, which is presented in Table 2. The average cost of gas for the region in the five year period 1961–1966 increased from 25 to 25.3 cents per million BTU or by 1.2 percent. The consumption of gas on a coal equivalent basis for the region in 1966 was approximately 11,101,000 tons.

[9] Averitt, op. cit. (footnote 6) p. 76.

TABLE 19

Estimated Original Reserves of Lignite of South Dakota

[In millions of short tons]

Thickness of bed (feet)	Reserves			Total
	Measured	Indicated	Inferred	
2½ to 5	104	993	177	1, 274
5 to 10	34	673	(1)	707
>10		52		52
Total	138	1, 718	177	2, 033

1 60 thousand tons not included in total.

TABLE 20

Estimated Lignite Reserves of South Dakota by County [1]

(In millions of short tons)

County	Remaining lignite reserves as of January 1, 1968—measured, indicated & inferred reserves
Dewey	138
Harding	1, 700
Perkins	186
Ziebach	6
Total	2, 030

1 Ward op. cit. (footnote 8).

Tables 26 and 27 which present a comparison of the percentage of total BTU's by type of fuel used for thermal electric generation in the West Central Region for 1961 and 1966 respectively, indicate the percent supplied by coal increased from 76 to 80 percent and gas decreased from 23 to 19 percent.

Table 21 lists the natural gas reserves in the West Central Region by states as of December 31, 1966 and the total for the region was 1.33 trillion cubic feet or less than one percent of the total reserves in the United States. On a coal equivalent basis of 23.75 million BTU per ton of coal and 1,000 BTU per cubic foot of gas the reported gas reserves for the region amounted to approximately 56 million tons of coal.

Based on the projected United States cumulative natural gas requirements for the period 1966 to 1990 of 680 trillion cubic feet [10] the reported reserves of the West Central Region could supply only 0.20 percent of these requirements.

Oil Consumption and Reserves

Table 27 compares the total BTU's of coal, oil and natural gas consumption for thermal electric generation in 1966 and oil consumption in the West Central Region represented less than 1 percent of the total fuel consumption for the region.

Table 23 lists the crude oil and natural gas liquid reserves in the West Central Region by states and the total for the region was 0.813 billion barrels or approximately 2 percent of the total liquid hydrocarbon reserves of the United States.

On a coal equivalent basis of 23.75 million BTU per ton of coal and 5.8 million BTU per barrel of oil the reported oil reserves for the region amount to approximately 200 million tons of coal.

10 Future Requirements Committee, 1967, Future Natural Gas Requirements of the United States, Vol. No. 2, June 1967, Denver Research Institute, p. 2–3.

TABLE 21

West Central Region—Changes in Estimated Proved Recoverable Reserves of Natural Gas, by State, During 1966

(Millions of cubic feet)

	Reserves as of Dec. 31, 1965	Changes in reserves during 1966						Reserves as of Dec. 31, 1966			
		Extensions	Revisions	New field discoveries	New reservoir discoveries	Net change in[1] underground storage	Net production	Total	Non-associated	Associated dissolved	Underground storage[2]
Illinois	209, 674	1, 973	1, 104	187	187	29, 207	5, 839	236, 493	277	31, 707	204, 506
Minnesota[3]											
Nebraska	79, 604	191	2, 024	176	0	1, 256	10, 494	72, 757	37, 838	19, 545	15, 374
North Dakota	1, 121, 224	8, 585	−64, 599	1, 619	99	0	42, 419	1, 024, 509	6, 497	1, 018, 012	0
Iowa & Missouri	(4)										
South Dakota & Wisconsin	0	0	0	0	0	0	0	0	0	0	0
Total	1, 410, 502	10, 749	−61, 461	1, 982	286	30, 463	58, 752	1, 333, 759	44, 612	1, 069, 264	219, 883
United States	286, 468, 923	9, 224, 745	4, 937, 962	2, 947, 329	3, 110, 396	134, 523	17, 491, 073	289, 332, 805	217, 426, 169	68, 681, 867	3, 224, 769
West Central Region as Percent of Total U.S.	0. 492							0. 461			

[1] The net difference between gas stored and gas withdrawn from underground storage reservoirs, inclusive of adjustments and native gas transferred from other reserve categories.
[2] Gas held in underground reservoirs (including native and net injected gas) for storage purposes.
[3] Geologists indicate the reserves listed for Minnesota in Gas Facts 1967 are in error.
[4] Trace quantities.

Source: American Gas Association, Bureau of Statistics, Gas Facts 1967 (1966 data).

WEST CENTRAL REGION
GAS RESERVES

FIGURE 3

WEST CENTRAL REGION
OIL RESERVES

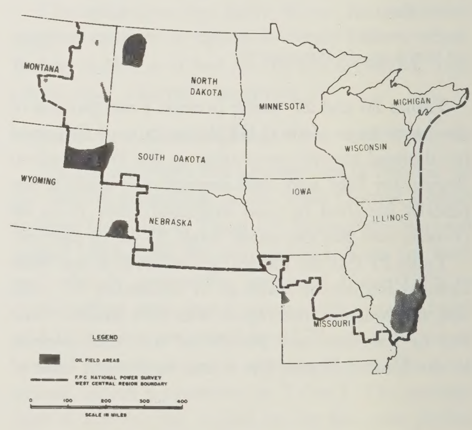

FIGURE 4

TABLE 22

West Central Region—Consumption of Gas for Electric Generation

	Year 1961			Year 1966		
	Consumption		Cost (Cents) per million btu as burned	Consumption		Cost (Cents) per million btu as burned
	Million cubic feet	BTU (Billions)		Million cubic feet	BTU (Billions)	
Illinois	33, 651	35, 266	24. 5	43, 165	45, 410	23. 7
Wisconsin	10, 723	11, 195	28. 3	16, 068	16, 325	31. 7
Missouri	35, 574	35, 965	22. 0	44, 681	44, 145	22. 5
Iowa	57, 069	58, 952	26. 1	61, 968	63, 207	26. 0
Minnesota	47, 867	48, 920	24. 4	51, 100	51, 611	25. 2
Subtotal	184, 884	190, 298	Avg. 24. 7	216, 982	220, 698	Avg. 25. 0
North Dakota	32	32	33. 2	22	22	33. 0
South Dakota	4, 897	4, 961	26. 0	3, 457	3, 471	28. 9
Nebraska	33, 092	34, 747	[1] 26. 4	39, 503	39, 463	26. 1
Subtotal	38, 021	39, 740	Avg. 26. 3	42, 982	42, 956	Avg. 26. 3
Total West Central Region	222, 905	230, 038	Avg. 25. 0	259, 964	263, 654	Avg. 25. 3

Increase in Gas Consumption for Generation in five year period 1961–1966	16. 62%
Average Annual Increase in Gas Consumption for Generation	3. 11%
Increase in Average Gas Price in five year period 1961–1966	1. 2%
Average Annual Increase in Gas Price	0. 24%

	1961	*1966*
West Central Region Gas Consumption (Coal Equivalent)	[2] 9,585,000 tons	[3] 11,101,000 tons

1964 National Power Survey, Part II, Page 326. Representative Delivered Costs of Natural Gas for Electric Power Generation by Load Study Areas.

Load Study Area	*Cents per million btu* *Jan. 1 1963*	*1966*
I (Ill. Wisc. Mo. Io. Minn.)	25	25. 0
L (N.D. S.D. Neb.)	26	26. 3

[1] 1961 price not available, therefore, 1962 price was used.

[2] Based on 24,000,000 BTU per ton of coal (approximate 1961 national average steam-electric plant experience).

[3] Based on 23,750,000 BTU per ton of coal (approximate 1966 national average steam-electric plant experience).

Source: National Coal Association, Steam-Electric Plant Factors 1961 & 1966. Federal Power Commission, Electric Power Statistics, monthly.

TABLE 23

West Central Region—Estimated Proved Recoverable Reserves of Liquid Hydrocarbons, by State, December 31, 1965 and 1966

(Thousands of barrels)

Division and State	Dec. 31, 1965	December 31, 1966		
		Total	Crude oil	Natural gas [1] liquids
Illinois	374, 184	365, 140	362, 270	2, 870
Minnesota	0	0	0	0
Nebraska	74, 323	59, 608	57, 134	2, 474
North Dakota	461, 280	388, 323	321, 349	66, 974
Iowa & Wisconsin	0	0	0	0
South Dakota & Missouri	([2])			
Total	909, 787	813, 071	740, 753	72, 318
United States	39, 375, 925	39, 781, 093	31, 452, 127	8, 328, 966
West Central Region as percent of total U.S.	2. 311	2. 044		

[1] Includes condensate, natural gasoline and liquefied petroleum gases.

[2] Trace quantities.

Source: American Gas Association, Bureau of Statistics, Gas Facts 1967 (1966 data).

TABLE 24

West Central Region—Changes in Estimated Proved Recoverable Reserves of Crude Oil, by State, During 1966

(Thousands of barrels)

Division and State	Reserves as of Dec. 31, 1965	Changes in reserves during 1966					Reserves as of Dec. 31, 1966
		Revisions	Extensions	New fields discovered	New pools discovered	Estimated production	
Illinois	371, 172	49, 781	1, 984	241	135	61, 043	362, 270
Minnesota	0	0	0	0	0	0	0
Nebraska	70, 659	−877	720	665	0	14, 033	57, 134
North Dakota	395, 140	−55, 456	7, 370	1, 390	85	27, 180	321, 349
Iowa & Wisconsin	0	0	0	0	0	0	0
South Dakota & Missouri	([1])						
Total	836, 971	−6, 552	10, 074	2, 296	220	102, 256	740, 753
United States	31, 352, 391	1, 839, 307	814, 249	160, 384	150, 038	2, 864, 242	31, 452, 127
West Central Region as percent of total U.S.	2. 67						2. 36

[1] Trace quantities.

Source: American Gas Association, Bureau of Statistics, Gas Facts 1967 (1966 data).

TABLE 25

West Central Region—Estimated Proved Recoverable Reserves of Natural Gas Liquids, by State, 1965 and 1966

(Thousands of barrels)

Division and State	Reserves as of Dec. 31, 1965	Changes in reserves during 1966: Extensions	Revisions	New field discoveries	New reservoir discoveries	Net production	Reserves as of December 31, 1966: Total	Non-associated	Associated-dissolved
Illinois	3, 012	179	168	34	0	523	2, 870	1	2, 869
Minnesota	0	0	0	0	0	0	0	0	0
Nebraska	3, 664	0	−814	0	0	376	2, 474	1, 204	1, 270
North Dakota	66, 140	0	4, 271	0	0	3, 437	66, 974	0	66, 974
Iowa & Missouri	0	0	0	0	0	0	0	0	0
South Dakota & Wisconsin	0	0	0	0	0	0	0	0	0
Total	72, 816	179	3, 625	34	0	4, 336	72, 318	1, 205	71, 113
United States	8, 023, 534	131, 583	634, 233	53, 378	74, 922	588, 684	8, 328, 966	5, 229, 261	3, 099, 705
West Central Region as Percent of Total U.S.	0. 908						0. 868		

Note: Includes condensate, natural gasoline, and liquefied petroleum gases.
Source: American Gas Association, Bureau of Statistics, Gas Facts 1967 (1966 data).

TABLE 26

West Central Region—Fuel Consumption in Billions of BTU's for Thermal Electric Generation—1961

	Total btu (billions): Coal	Oil	Gas	Total	Percent of total btu: Coal	Oil	Gas
Illinois	431, 746	1, 979	35, 266	468, 991	92	....	8
Wisconsin	123, 195	273	11, 195	134, 663	92	....	8
Missouri	81, 358	1, 594	35, 965	118, 917	69	1	30
Iowa	40, 128	1, 285	58, 952	100, 365	40	1	59
Minnesota	62, 325	1, 992	48, 920	113, 237	55	2	43
Subtotal	738, 752	7, 123	190, 298	936, 173	79	1	20
North Dakota	15, 681	123	32	15, 836	99	1	....
South Dakota	3, 951	312	4, 961	9, 224	43	3	54
Nebraska	5, 336	909	34, 747	40, 992	13	2	85
Subtotal	24, 968	1, 344	39, 740	66, 052	38	2	60
Total West Central Region	763, 720	8, 467	230, 038	1, 002, 225	76	1	23

Source: National Coal Association, Steam-Electric Plant Factors 1961. Federal Power Commission, Electric Power Statistics, monthly.

TABLE 27

West Central Region—Fuel Consumption in Billions of BTU's for Thermal Electric Generation—1966

	Total btu (billions)				Percent of total btu		
	Coal	Oil	Gas	Total	Coal	Oil	Gas
Illinois	589, 984	3, 021	45, 410	638, 415	93	....	7
Wisconsin	181, 159	650	16, 325	198, 134	91	1	8
Missouri	125, 350	1, 257	44, 145	170, 752	73	1	26
Iowa	60, 366	1, 465	63, 207	125, 038	48	1	51
Minnesota	101, 084	2, 218	51, 611	154, 913	65	2	33
Subtotal	1, 057, 943	8, 611	220, 698	1, 287, 252	82	1	17
North Dakota	[1] 26, 722	14	22	26, 758	100	....	....
South Dakota	3, 777	308	3, 471	7, 556	50	4	46
Nebraska	10, 234	799	39, 463	50, 496	20	2	78
Subtotal	40, 733	1, 121	42, 956	84, 810	48	1	51
Total West Central Region	1, 098, 676	9, 732	263, 654	1, 372, 062	80	1	19

[1] Based on additional data obtained in West Central Region Fuel Survey.

Source: National Coal Association, Steam-Electric Plant Factors 1966. Federal Power Commission, Electric Power Statistics, monthly.

FOSSIL FUEL SURVEY

Definition of Bituminous Coal and Lignite Producing Districts

DISTRICT 1.—EASTERN PENNSYLVANIA

Pennsylvania

Armstrong County (part).—All mines east of Allegheny River, and those mines served by the Pittsburgh & Shawmut Railroad located on the west bank of the river.

Fayette County (part).—All mines located on and east of the line of Indian Creek Valley branch of the Baltimore & Ohio Railroad.

Indiana County (part).—All mines not served by the Saltsburg branch of the Pennsylvania Railroad.

Westmoreland County (part).—All mines served by the Pennsylvania Railroad from Torrance, east.

All mines in the following counties:

Bedford	Forest
Blair	Fulton
Bradford	Huntingdon
Cambria	Jefferson
Cameron	Lycoming
Centre	McKean
Clarion	Mifflin
Clearfield	Potter
Clinton	Somerset
Elk	Tioga

Maryland.—All mines in the State.

West Virginia.—All mines in the following counties:

Grant	Tucker
Mineral	

DISTRICT 2.—WESTERN PENNSYLVANIA

Pennsylvania

Armstrong County (part).—All mines west of the Allegheny River except those mines served by the Pittsburgh & Shawmut Railroad.

Fayette County (part).—All mines except those on and east of the line of Indian Creek Valley branch of the Baltimore & Ohio Railroad.

Indiana County (part).—All mines served by the Saltsburg branch of the Pennsylvania Railroad.

Westmoreland County (part).—All mines except those served by the Pennsylvania Railroad from Torrance, east.

All mines in the following counties:

Allegheny	Lawrence
Beaver	Mercer
Butler	Venango
Greene	Washington

DISTRICT 3.—NORTHERN WEST VIRGINIA

West Virginia

Nicholas County (part).—All mines served by or north of the Baltimore & Ohio Railroad.

All mines in the following counties:

Barbour	Preston
Braxton	Randolph
Calhoun	Ritchie
Doddridge	Roane
Gilmer	Taylor
Harrison	Tyler
Jackson	Upshur
Lewis	Webster
Marion	Wetzel
Monongalia	Wirt
Pleasants	Wood

DISTRICT 4.—OHIO.—All mines in the State.

DISTRICT 5.—MICHIGAN.—All mines in the State.

DISTRICT 6.—PANHANDLE

West Virginia.—All mines in the following counties:

Brooke	Marshall
Hancock	Ohio

DISTRICT 7.—SOUTHERN NO. 1

West Virginia

Fayette County (part).—All mines east of Gauley River and all mines served by the Gauley River branch of the Chesapeake & Ohio Railroad and mines served by the Virginian Railway.

McDowell County (part).—All mines in that portion of the county served by the Dry Fork branch of the Norfolk & Western Railroad and east thereof.

Raleigh County (part).—All mines except those on the Coal River branch of the Chesapeake & Ohio Railroad and north thereof.

Wyoming County (part).—All mines in that portion served by the Gilbert branch of the Virginian Railway lying east of the mouth of Skin Fork of Guyandot River and in that portion served by the main line and the Glen Rogers branch of the Virginian Railway.

All mines in the following counties:

Greenbrier	Mercer
Monroe	Summers
Pocahontas	

Virginia

Buchanan County (part).—All mines in that portion of the county served by the Richlands-Jewell Ridge branch of the Norfolk & Western Railroad and in that portion on the headwaters of Dismal Creek east of Lynn Camp Creek (a tributary of Dismal Creek).

Tazewell County (part).—All mines in those portions of the county served by the Dry Fork branch to Cedar Bluff and from Bluestone Junction to Boissevain branch of the Norfolk & Western Railroad and Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

All mines in the following counties:

Montgomery	Giles
Pulaski	Craig
Wythe	

DISTRICT 8.—SOUTHERN NO. 2

West Virginia

Fayette County (part).—All mines west of the Gauley River except mines served by the Gauley River branch of the Chesapeake & Ohio Railroad.

McDowell County (part).—All mines west of and not served by the Dry Fork branch of the Norfolk & Western Railroad.

Nicholas County (part).—All mines in that part of the county south of and not served by the Baltimore & Ohio Railroad.

Raleigh County (part).—All mines on the Coal River branch of the Chesapeake & Ohio Railroad and north thereof.

Wyoming County (part).—All mines in that portion served by the Gilbert branch of the Virginian Railway and lying west of the mouth of Skin Fork of Guyandot River.

All mines in the following counties:

Boone	Logan
Cabell	Mason
Clay	Mingo
Kanawha	Putnam
Lincoln	Wayne

Virginia

Buchanan County (part).—All mines in the county, except in that portion on the headwaters of Dismal Creek, east of Lynn Camp Creek (a tributary of Dismal Creek) and in that portion served by the Richlands-Jewell

Ridge branch of the Norfolk & Western Railroad.

Tazewell County (part).—All mines in the county except in those portions served by the Dry Fork branch of the Norfolk & Western Railroad and branch from Bluestone Junction to Boissevain of Norfolk & Western Railroad and Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

All mines in the following counties:

Dickinson	Scott
Lee	Wise
Russell	

Kentucky.—All mines in the following counties in eastern Kentucky:

Bell	Lawrence
Boyd	Lee
Breathitt	Leslie
Carter	Letcher
Clay	McCreary
Elliott	Magoffin
Floyd	Martin
Greenup	Morgan
Harlan	Owsley
Jackson	Perry
Johnson	Pike
Knott	Rockcastle
Knox	Wayne
Laurel	Whitley

Tennessee.—All mines in the following counties:

Anderson	Morgan
Campbell	Overton
Claiborne	Putnam
Cumberland	Roane
Fentress	Scott

North Carolina.—All mines in the State.

DISTRICT 9.—WEST KENTUCKY

Kentucky.—All mines in the following counties in western Kentucky:

Butler	McLean
Christian	Muhlenberg
Crittenden	Ohio
Daviess	Simpson
Hancock	Todd
Henderson	Union
Hopkins	Warren
Logan	Webster

DISTRICT 10.—ILLINOIS.—All mines in the State.

DISTRICT 11.—INDIANA.—All mines in the State.

DISTRICT 12.—IOWA.—All mines in the State.

DISTRICT 13.—SOUTHEASTERN

Alabama.—All mines in the State.

Georgia.—All mines in the following counties:

Dade	Walker

Tennessee.—All mines in the following counties:

Bledsoe	Rhea
Grundy	Sequatchie
Hamilton	Van Buren
Marion	Warren
McMinn	White

DISTRICT 14.—ARKANSAS-OKLAHOMA

Arkansas.—All mines in the State.

Oklahoma.—All mines in the following counties:

Haskell	Sequoyah
Le Flore	

DISTRICT 15.—SOUTHWESTERN

Kansas.—All mines in the State.

Missouri.—All mines in the State.

Oklahoma.—All mines in the following counties:

Coal	Pittsburg
Craig	Rogers
Latimer	Tulsa
Muskogee	Wagoner
Okmulgee	

DISTRICT 16.—NORTHERN COLORADO

All mines in the following counties in the State:

Adams	El Paso
Arapahoe	Jackson
Boulder	Jefferson
Douglas	Larimer
Elbert	Weld

DISTRICT 17.—SOUTHERN COLORADO

Colorado.—All mines except those included in District 16.

New Mexico.—All mines except those included in District 18.

DISTRICT 18.—NEW MEXICO

New Mexico.—All mines in the following counties:

Grant	McKinley
Lincoln	Rio Arriba

Sandoval
San Juan
San Miguel
Santa Fe
Socorro

Arizona.—All mines in the State.
California.—All mines in the State.

DISTRICT 19.—WYOMING

Wyoming.—All mines in the State.
Idaho.—All mines in the State.

DISTRICT 20.—UTAH.—All mines in the State.

DISTRICT 21.—NORTH DAKOTA-SOUTH DAKOTA.—All mines in North Dakota and South Dakota.

DISTRICT 22.—MONTANA.—All mines in the State.

DISTRICT 23.—WASHINGTON

Washington.—All mines in the State.
Oregon.—All mines in the State.
Alaska.—All mines in the Territory.

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CHAPTER III

GENERAL PATTERNS OF GENERATION AND TRANSMISSION

Introduction

The purpose of this report is to provide general information relating to anticipated patterns of generation and transmission in the West Central Region during the period through 1990. Developing and presenting this information was accomplished by means of a specific pattern for each of the years 1970, 1980 and 1990.

Generating Facilities

About 90 per cent of the electric energy produced in the West Central Region is presently supplied by conventional steam-electric generating plants. Most of the remaining generation is supplied from hydroelectric resources and much of this from the Federally owned and operated projects in the Missouri River Basin. About 100 small privately-owned hydroelectric projects are located on the upper Mississippi River and its tributaries in Wisconsin and Minnesota. Only 226 megawatts of nuclear power are now in productive operation in the West Central Region, less than one per cent of the total supply.

Tables 2, 3, and 4 show the over-all projections of generation expansion for the West Central Region classified into subtotals by PSA, types of generation and size, and approximate geographic location. The expansion shown is intended only to generally depict that which is presently believed to be a likely pattern of development of generating sources to serve the loads forecasted through 1990. In this effort, fully coordinated planning and operation of all electric systems in the region is assumed to be a reality by the the 1980–1990 period. A comparison of these power supply sources and the anticipated load in the West Central Region, detailed in the section entitled Load and Energy Projections, indicates the reserve generating capacity to be 20.8% in 1970, 15.6% in 1980, and 16.6% in 1990. These values are based upon seasonally coincident loads but do not reflect the additional reserve which results from diversity of load requirements between utilities during a given season. The reduction in reserve after 1970 comes about from a more coordinated use of surplus generation and diversity, and from an anticipated integration of planning and operation of smaller systems with the coordinated operation of large systems. The individual PSA capacity and load relationships are not necessarily in balance, due to economic unit sizing and location considerations. The assumed power transfers between PSA's are noted in Table 3.

In developing the pattern of power supply for the region, information was provided by individual systems, coordinating groups and area study groups from projections of generating capacity additions and retirements. As such the generation expansion plans reflect the overall judgment of a number of planning organizations concerning the mix of nuclear and fossil base generation and the amount of peaking capacity to properly balance this generation. The anticipated retirement of capacity in each system was governed by age of equipment, economic consideration and peaking service requirements and generally conforms to about 35 years expected life for both fossil-fueled steam generators and diesel generators. Most hydro equipment was considered replaced in kind. Inasmuch as the equipment retired is of the small unit classification, the replacement of this capacity is projected to be with equipment which falls approximately in the same category because of the continued need for peaking capacity.

The development for 1990 is extracted and shown in Table 1. This table summarizes the amount of various types of generating capacity in each PSA and shows a total of 151,041 megawatts designed to supply a non-coincident summer peak demand which is elsewhere predicted to be 130,240 megawatts. It indicates that 57 per cent of the electric generating resources by the end of the report period might be anticipated to consist of nuclear-type gen-

TABLE 1

1990 Net Generating Capacity in Megawatts

	PSA									Total
	13	14	15	16	17	26	27	28	40	
Source of capacity:										
Diesel and gas turbines	1, 305	4, 726	1, 200	1, 180	1, 424			102	830	10, 767
Conventional hydro	305		358	254			2, 580	120		3, 617
Pumped storage			350							350
Steam-electric fossil fuel:										
0–399 mw units	8, 822	1, 660	1, 426	3, 857	3, 322	680	1, 794	1, 525	6, 055	29, 141
400–799 mw units		1, 715	3, 414	580			4, 400		4, 400	14, 509
800–1199 mw units			1, 600	2, 200					2, 800	6, 600
1200 mw and over										
Nuclear:										
0–399 mw units		200		86						286
400–799 mw units	6, 427			3, 675	2, 900			4, 633		17, 635
800–1199 mw units	800	10, 918	4, 200	3, 300	7, 418			3, 000	1, 600	31, 236
1200 mw and over		16, 500	7, 200	4, 500	3, 000				5, 700	36, 900
Total capacity	17, 659	35, 719	19, 748	19, 632	18, 064	680	8, 774	9, 380	21, 385	151, 041
Percent distribution:										
Diesel and gas turbines	7	13	6	6	8			1	3	7
Conventional hydro	2		2	2			29	2		3
Pumped storage			2							0
Steam-electric fossil fuel	50	10	32	33	18	100	71	16	62	33
Nuclear	41	77	58	59	74			81	35	57
Totals	100	100	100	100	100	100	100	100	100	100

eration (contrasted to 32% in 1980) and 33 per cent of fossil-fueled steam-type generation. The remaining 10 per cent is peaking capacity although additional peaking capacity is included in the fossil fuel category. Less than 1 per cent is shown as pumped storage which is that presently existing. A number of potential pumped storage and conventional hydro sites exist which have been examined in varying degrees of thoroughness. Although several regional utilities have studied the economics of installing pumped storage facilities, to date additional installations of this type of generation have not been committed. It is recognized that pumped storage hydro does complement nuclear generation and continuing studies are anticipated which may determine justification for such developments. Such studies must weigh the load factor involved, availability and cost of fuel, capital costs and technical operating considerations.

Almost half of the 1990 capacity is shown to be in units of 800 megawatts or larger. Generator unit sizes up to 2000 megawatts and total plant size up to 4000 mw are included.

There appears to be no lack of reasonably available resources for the generation of electric energy to meet power requirements for many decades ahead. In addition to the major role which will be played by nuclear fuel, fuel supplies needed for major expansions in conventional steam-electric generation in the eastern part of the West Central Region are abundantly available in the bituminous coal fields of south central Illinois, lower Indiana, western Kentucky, west central Missouri and southern Iowa. Large deposits of lignite are situated in North Dakota and eastern Montana and sub-bituminous coal in eastern Montana and Wyoming. The locations of these deposits are described in the Inventory of Fossil Fuel Resources. Water as well as rail transportation is available for movement of these fuel supplies to many of the major centers of generation. The navigable waterways of the Mississippi, Ohio, Tennessee and Illinois Rivers afford economic access to coal fields and the waterways of the Mississippi, Illinois and Missouri Rivers and the Great Lakes permit extensive distribution of coal supplies into the area.

356–240 O—70——14

TABLE 2

FPC—West Central Region—Patterns of Generation and Transmission; Projected Total Generating Capacity, Megawatts

PSA	1970	1980	1990
13	5, 729	10, 076	17, 659
14	10, 435	18, 960	35, 719
15	4, 335	11, 198	19, 748
16	5, 215	9, 503	19, 632
17	4, 205	9, 826	18, 064
26	280	680	680
27	3, 082	4, 424	8, 774
28	1, 747	4, 880	9, 380
40	7, 037	10, 285	21, 385
Total	42, 065	79, 832	151, 041

In determining the relative economics of nuclear versus fossil fuel generation in the region, consideration has been given to the installation of mine-mouth plants in southern Illinois (high grade bituminous coal) and similarly in North Dakota (lignite fields). The advantages of low fuel costs outweighing the higher transmission cost make many of these sites economically attractive. However, in considering the use of such generation, practical economic requirements place limitations upon the transmission of large blocks of power and energy over distances generally in excess of 500 miles unless a portion of the capital cost of associated transmission facilities can be assigned to area service requirements and system integrity.

Although an extensive network of natural gas pipelines extends into the West Central Region

TABLE 3A

FPC—West Central Region—Patterns of Generation and Transmission, 1970 Net Generating Capacity in Megawatts

	PSA									Total
	13	14	15	16	17	26	27	28	40	
Source of capacity:										
Diesel and gas turbines	475	1, 126	300	439	539			102	330	3, 311
Conventional hydro	305		358	303	15		2, 048	120		3, 149
Pumped storage			350							350
Steam-electric fossil fuel:										
0–399 mw units	4, 495	5, 852	2, 313	3, 287	2, 880	280	1, 034	1, 525	5, 507	27, 173
400–799 mw units		1, 715	1, 014	580					1, 200	4, 509
800–1,199 mw units										
1,200 mw and over										
Nuclear:										
0–399 mw units		200		86						286
400–799 mw units	454			520						974
800–1,199 mw units		1, 542			771					2, 313
1,200 mw and over										
Total capacity	5, 729	10, 435	4, 335	5, 215	4, 205	280	3, 082	1, 747	7, 037	42, 065
Percent distribution:										
Diesel and gas turbines	8	11	7	8	13			6	5	8
Conventional hydro	5		8	6			60	7		7
Pumped storage			8							1
Steam-electric fossil fuel	79	72	77	73	68	100	40	87	95	75
Nuclear	8	17		13	19					9
Total	100	100	100	100	100	100	100	100	100	100

NOTES. 1. Preference customer load in PSA 16 is assumed to be 130 mw in 1970. Served by generation in PSA 27.
2. 1,000 mw of Joppa Plant is included in PSA 40.
3. Preference customer load in PSA 17 is assumed to be 155 mw in 1970. Served by generation in PSA 27.
4. All of State Line is included in PSA 14 rather than PSA 12 of the East Central Region.
5. 555 mw of PSA 40 generation for PSA 15.
6. 1,552 mw of PSA 40 generation for PSA 14.
7. 365 mw of PSA 17 generation for PSA 14.

from gas fields in Oklahoma, Kansas, Louisiana, and Texas, firm natural gas supplies are not currently available in sufficient quantities to fuel completely full scale generating facilities in the region and, in any event, the utilities are not in a position to construct new generating stations which are designed only for the burning of natural gas at or near prevailing prices. In view of the availability of alternative fuels at prices well below what firm gas would have to command and the rapidly expanding demands for natural gas for other uses it is unlikely that such contracts will be consumated by the utilities of the region.

To date, nuclear power has been adjudged feasible where conventional fuel costs remain above approximately 25 cents per million Btu. Such judgments have been influenced by the elimination of fossil fuel air pollution, the logistics of fossil fuel transport and an anticipated greater reliability of nuclear generation. However, current decisions to install additional generation are being subjected to substantially increased capital costs of both nuclear and fossil-fueled facilities, to reductions in fuel transportation costs for large coal movements by unit train, to the need for gaining experience with those units previously committed, and a desire

TABLE 3B

FPC—West Central Region—Patterns of Generation and Transmission, 1980 Net Generating Capacity in Megawatts

	PSA									Total
	13	15	16	16	17	26	27	28	40	
Source of capacity:										
Diesel and gas turbines	598	2, 326	1, 100	738	856			102	230	5, 950
Conventional hydro	305		358	303	2		2, 080	120		3, 168
Pumped storage			350							350
Steam-electric fossil fuel:										
0–399 mw units	5, 850	4, 601	1, 576	3, 791	3, 200	680	1, 344	1, 525	6, 055	28, 622
400–799 mw units		1, 715	3, 414	580			1, 000		3, 200	9, 909
800–1,199 mw units			1, 600						800	2, 400
1,200 mw and over										
Nuclear:										
0–399 mw units		200		86						286
400–799 mw units	3, 323			2, 905	1, 050			3, 133		10, 411
800–1,199 mw units		10, 118	1, 600	1, 100	3, 218				0	16, 036
1,200 mw and over			1, 200		1, 500					2, 700
Total Capacity	10, 076	18, 960	11, 198	9, 503	9, 826	680	4, 424	4, 880	10, 285	79, 832
Percent distribution:										
Diesel and gas turbines[1]	6	12	10	8	8			2	2	7
Conventional hydro	3		3	3			46	3		4
Pumped storage			3							1
Steam-electric fossil fuel	58	34	59	45	33	100	54	31	98	51
Nuclear	33	54	25	44	59			64	0	37
Total	100	100	100	100	100	100	100	100	100	100

[1] May be supplemented by pumped storage hydro for peaking service.

NOTES. 1. 1,000 mw of Joppa Plant is included in PSA 40.

2. Preference customer load in PSA 16 is assumed to be 250 mw by 1980. Served by generation in PSA 27.
3. The Manitoba Hydro development delivers 800 mw to PSA 16 by 1980 through 1990.
4. Preference customer load in PSA 17 is assumed to be 293 mw by 1980. Served by generation in PSA 27.
5. By 1980 the CPPD Cooper plant development in PSA 28 delivers 400 mw to PSA 17 which continues beyond 1990.
6. All of State Line is included in PSA 14 rather than PSA 12 of East Central Region.
7. 960 mw of PSA 40 generation for PSA 14.
8. 2,309 mw of PSA 17 generation for PSA 14.

to maintain a diversity of supply. A substantial reduction in costs can be achieved for both nuclear and conventional power plants by increasing the size of generating units, and joint participation in plants of large size consequently will be studied closely.

Because the thermal efficiency of nuclear plants is somewhat less than that for modern fossil-fueled plants, nuclear plants require about 40% more cooling water. However, there need be no adverse effect on aquatic ecology if cooling water discharge temperatures are held within acceptable limits.

The Water Quality Act of 1965 places the responsibility for the development of state standards and interstate standards with the states involved. Such standards must be approved by the Secretary of the Interior. For the most part, new water quality standards have been adopted by the respective states and approved by the Secretary of the Interior. The enforcement of approved water quality standards is the responsibility of the respective states, with the Federal Water Pollution Control Administration acting as a secondary enforcement agency.

TABLE 3C

FPC—West Central Region—Patterns of Generation and Transmission, 1990 Net Generating Capacity in Megawatts

	PSA									Total
	13	14	15	16	17	26	27	28	40	
Source of capacity:										
Diesel and gas turbines	1,305	4,726	1,200	1,180	1,424			102	830	10,767
Conventional hydro	305		358	254			2,580	120		3,617
Pumped storage			350							350
Steam-electric fossil fuel:										
0–399 mw units	8,822	1,660	1,426	3,857	3,322	680	1,794	1,525	6,055	29,141
400–799 mw units		1,715	3,414	580			4,400		4,400	14,509
800–1,199 mw units			1,600	2,200					2,800	6,600
1,200 mw and over										
Nuclear:										
0–399 mw units		200		86						286
400–799 mw units	6,427			3,675	2,900			4,633		17,635
800–1,199 mw units	800	10,918	4,200	3,300	7,418			3,000	1,600	31,236
1,200 mw and over		16,500	7,200	4,500	3,000				5,700	36,900
Total capacity	17,659	35,719	19,748	19,632	18,064	680	8,774	9,380	21,385	151,041
Percent distribution:										
Diesel and gas turbines [1]	7	13	6	6	8			1	3	7
Conventional hydro	2		2	2			29	2		3
Pumped storage			2							0
Steam-electric fossil fuel	50	10	32	33	18	100	71	16	62	33
Nuclear	41	77	58	59	74			81	35	57
Total	100	100	100	100	100	100	100	100	100	100

[1] May be supplemented by pumped storage hydro for peaking service.

NOTES:

1. 1,000 mw of Joppa Plant is included in PSA 40.
2. The Manitoba Hydro development delivers 800 mw to PSA 16 through 1990.
3. Preference customer load in PSA 17 is assumed to be 538 mw by 1990. Served by generation in PSA 27.
4. Preference customer load in PSA 16 is assumed to be 500 mw by 1990. Served by generation in PSA 27.
5. The CPPD Cooper plant development in PSA 28 delivers 400 mw to PSA 17 which continues beyond 1990.
6. All of State Line is included in PSA 14 rather than PSA 12 of the East Central Region.
7. 1,980 mw of PSA 40 generation for PSA 15.
8. 3,060 mw of PSA 40 generation for PSA 14.
9. 3,809 mw of PSA 17 generation for PSA 14.

WEST CENTRAL REGION GENERATION AREAS

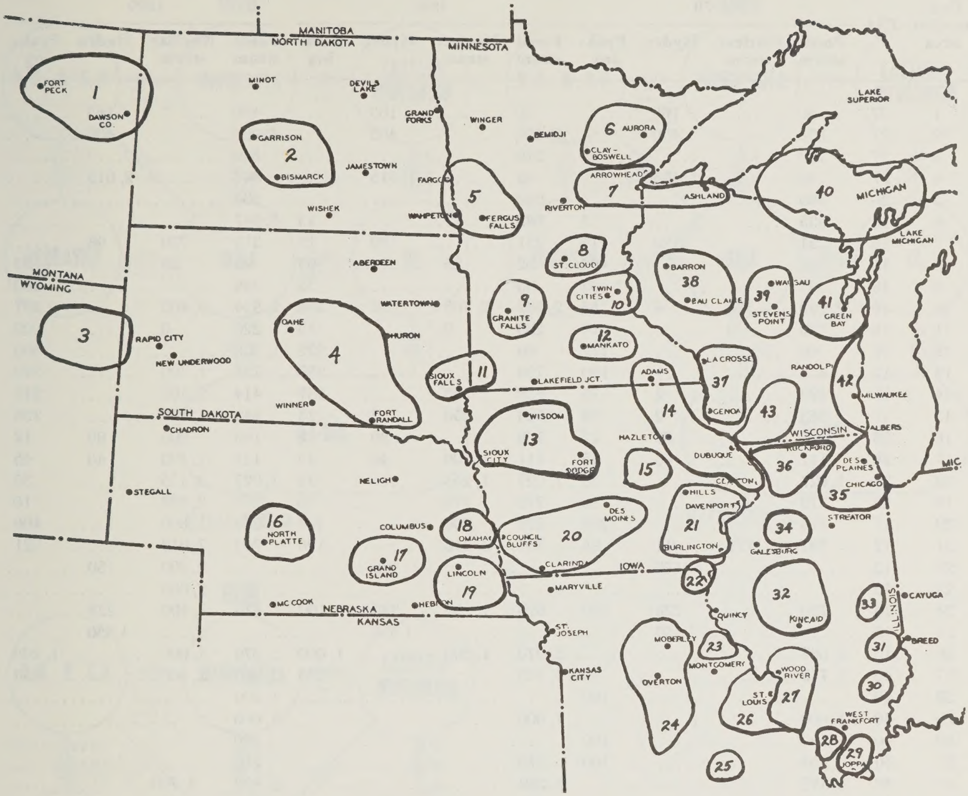

FIGURE 1

TABLE 4

FPC—West Central Region—Generation Patterns

Generation area	PSA	1970				1980				1990			
		Fossil steam	Nuclear steam	Hydro	Peaking	Fossil steam	Nuclear steam	Hydro	Peaking	Fossil steam	Nuclear steam	Hydro	Peaking
1	27	50		165		50		165		450		165	
2	27	826		400		2,036		400		4,036		400	
3	27	110				210				860			
4	27	48		1,483		48		1,515		848		2,015	
5	26	280				680				680			
6	16	535			13	885			13	1,047			
7	16	251		120	19	251		120	19	315	770	98	
8	16	52	26		93	52	26		93	25	26		83
9	16	95			32	95			32	246			200
10	16	2,098	520	6	58	2,102	2,705	6	208	2,954	9,405		397
11	16	138	0		16	288	0		15	220	0		200
12	16	66			172	66			322	1,300			300
13	17	413			130	738			280	738	1,300		329
14	17	429		2	76	458	500		137	414	2,100		213
15	17	663		2	33	663	550	2	115	649	1,100		255
16	28	108		80	12	108		80	12	108	800	80	12
17	28	111		40	45	111	1,100	40	45	111	1,100	40	45
18	28	1,027			35	1,027	1,255		35	1,027	3,155		35
19	28	279			10	279	778		10	279	2,578		10
20	17	578			204	578	800		198	778	1,800		406
21	17	797	771	11	96	763	3,918		126	743	7,018		221
22	15			130				130			2,400	130	
23	15										2,600		
24	15	720		228	300	620	1,200	228	100	470	2,400	228	
25	15			[1] 350				[1] 350				[1] 350	
26	15	2,607				5,970	1,600		1,000	5,970	4,000		1,200
27	40	1,715			30	3,365			230	3,365	2,400		830
28	40				100					1,200			
29	40	1,000				1,000				1,000			
30	40	250			100					800			
31	40	210			100	210				210			
32	40	3,332				5,280				6,480	3,700		
33	40	200				200				200	1,200		
34	14	300				300	3,000			300	6,800		
35	14	6,908	1,742		1,053	5,858	7,318		2,253	3,075	16,618		4,353
36	14	359			73	158			73		4,200		373
37	16	630	60			630	590			530	590		
38	16	2		177	36	2	770	177	36		770	156	
39	13	185		126	62	227		126	62	282		126	82
40	13	254		168	117	455		168	170	966		168	204
41	13	635	454	11	41	747	1,519	11	81	953	2,319	11	161
42	13	2,780			86	3,780	750		94	5,980	2,000		329
43	13	641			169	641	1,054		191	641	2,908		529

[1] Pumped hydro.

INDICATIVE TRANSFER CAPACITIES IN MW BETWEEN SYSTEMS IN WEST CENTRAL REGION

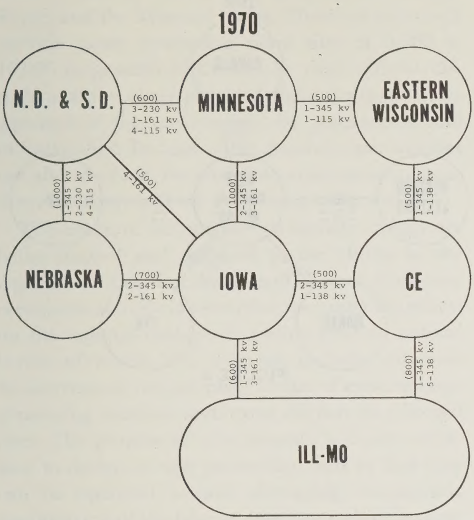

FIGURE 2

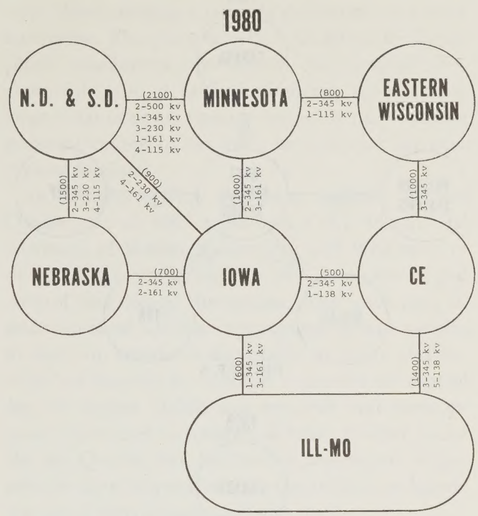

FIGURE 3

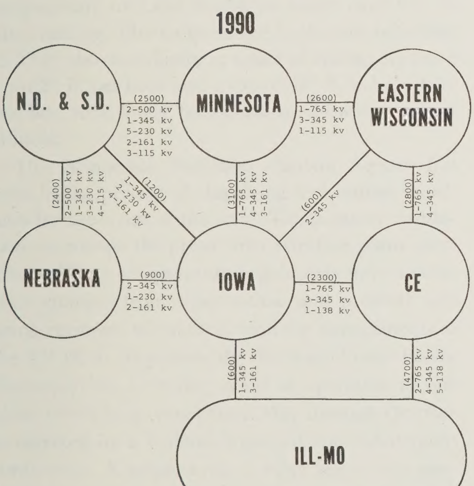

FIGURE 4

INDICATIVE TRANSFER CAPACITIES IN MW – WEST CENTRAL REGION AND SURROUNDING SYSTEMS

1970

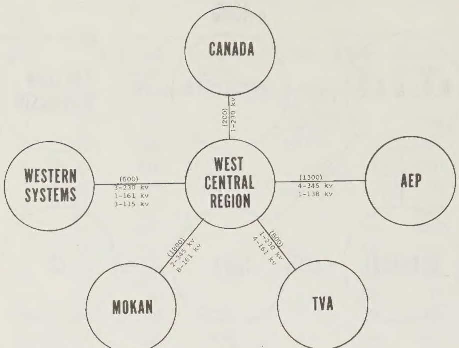

FIGURE 5

1980

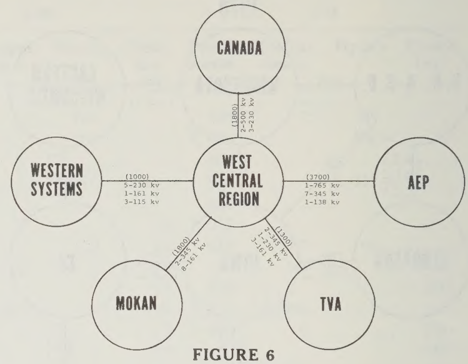

FIGURE 6

1990

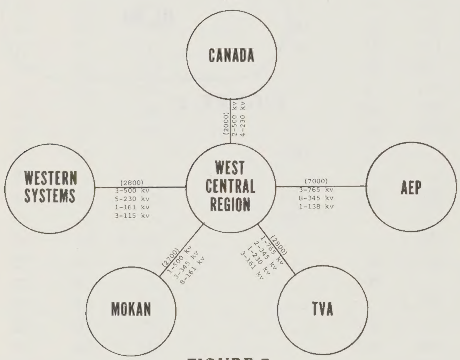

FIGURE 7

The West Central Region has some of the largest natural cooling water resources in the nation, i.e., Lake Superior, Lake Michigan, the Mississippi River, and the Missouri River. These resources will provide many generating plant sites of 5,000 to 10,000 megawatts which can be used without disturbing the ecology provided there is proper management of the environment by government and industry alike. In many areas ground water supplies are also available for moderate amounts of generation requiring conventional cooling tower use.

The effects of warm water on aquatic ecology are being studied and reflected in the efforts of the region's utilities. Commonwealth Edison Company is engaged actively in research concerning the effects on the aquatic ecology of adding heat to natural bodies of water. This research includes extensive measurements and sampling at sites of existing large generating stations and extrapolation to planned sites. The purpose of this research is to determine how to design its new generating units so that they can be operated without damaging the aquatic environment of the lake or river from which cooling water will be obtained. The water standards of the state of Illinois require that no effluent raise the temperature of Lake Michigan water over 85° F. after mixing. The temperature in streams is limited to 5° F. above ambient, at a rate of change no more than 2° F. per hour and a top of 93° F. in industrial reaches, with lower temperatures elsewhere within Illinois.

The Minnesota Pollution Control Agency has been in the process of classifying and setting standards for the rivers of the state. Temperature regulations constitute the prime area affecting plant operations. These temperature regulations have undergone changes from time-to-time and presently are being reviewed to conform with the requirements of the FWPCA. At present the Northern States Power Company has a cooling pond in operation at one plant which is operated from May through October as directed by a Federal-State pollution abatement conference. A helper-cycle cooling tower was constructed and is operated at the newest generating plant in conformance with the terms of the permit issued by the State agency. This limits the plant effluent temperature to 86° F. Cooling towers are included in the design of two large nuclear plants presently under construction in anticipation of state agency temperature limitations of 86° F. for mixed water or 5° over ambient. Capital costs for cooling facilities to date are estimated at $10,000,000 for plants totaling 2700 megawatts.

One utility in the area is constructing a 20 megawatt plant utilizing a recently developed air cooled condenser. This plant is to be a prototype for larger plant installations now under consideration. Because this type of facility eliminates the need for large quantities of cooling water, it may provide greater freedom in the siting of moderate size generating facilities.

In addition to state and local agencies, the Air Quality Act of 1967 introduces a new factor. The Secretary of Health, Education, and Welfare is to designate air quality regions and issue criteria and control technology documents. The governors of states involved will have approximately nine months to draw up standards acceptable to HEW and another six months to establish a method of control for the region. Additional research and development of control technology is being funded under the Air Quality Act, but to date the control strategies commercially available to the utilities are largely the use of precipitators and high stacks.

The concern of Wisconsin companies for proper and effective control of air and water pollution has been expressed by the formation of an active task force on air and water criteria. This task force, which is sponsored by the Wisconsin Utilities Association, has been working with the Wisconsin State Department of Natural Resources to provide the Department with data on the problems of establishing adequate criteria for the control of air and water pollution. This task force has provided the Department with information on studies being conducted by a number of Wisconsin utilities. It is hoped that the results of these studies will provide the industry with knowledge that can be used to properly assess the degree and consequence of water and air pollution.

The problem of air pollution weighs heavily in the choosing of generation sites, the type of fuel used, the capital costs of equipment to maintain acceptable conditions, and ultimately on what the cost to the customer will be. The future will remain uncertain until air quality and emission standards are defined more clearly and equipment for reducing sulfur emissions is developed and becomes available commercially.

In addition to studies of water and air problems, Wisconsin utilities are improving their control of fly ash through the installation of more efficient precipitators and taller stocks in existing plants and

through the substitution of gas for coal at some plants and the installation of nuclear-fueled units rather than fossil plants. New coal-fueled plants feature high stacks and high efficiency precipitators.

For the Commonwealth Edison Company, its Clean Air Program provides for the siting of new coal-fired generating capacity outside the Chicago Metropolitan area, accelerating the retirement of many of its older, less efficient coal-fired generating units, installing nuclear capacity instead of coal-fired capacity where economically feasible to do so, and burning large quantities of off-peak natural gas in the boilers of its Chicago area generating stations. Additionally, Commonwealth is participating in the City of Chicago's Air Pollution Incident Control Plan. The company has agreed, during periods of severe and prolonged air stagnation (over 36 hours), that it will when requested by the City, reduce by up to 22 percent the amount of production from its coal-fired units in Chicago by shifting generation to remote stations and will burn natural gas fuel in the boilers of those units to the extent such gas is available.

Commonwealth has already spent about $50 million for the abatement of air pollution by installing high stacks, high efficiency electrostatic precipitators, and gas burning facilities on coal-fired generating units. The company plans to spend several millions of dollars more over the next few years on further improvements to existing facilities.

Since 1956, Commonwealth has retired 14 old coal-fired generating units and plans to retire 12 more by 1970. The retirement of these units will be hastened by the installation of over 1.3 million kw of fast-start peaking capacity which will be fueled principally with natural gas. By 1972, the company plans to have retired all of its coal-fired generating units in Chicago which are not equipped with high efficiency precipitators. No new coal-fired units have been built in or near Chicago since 1962.

As a result of its program, Commonwealth will, between 1965 and 1972, reduce the amount of coal consumed in its Chicago generating stations by 40 percent.

Argonne National Laboratory, under contract with the City of Chicago, is developing mathematical techniques for implementing Chicago's Air Pollution Incident Control Plan. Commonwealth is cooperating in this study by participating in field tests and supplying technical information.

The Union Electric Company is continuing to use electrostatic precipitators in its new plants. In the recently completed Sioux plant, both units have 600 ft. stacks with 98% efficiency precipitators with cyclone boilers. This is roughly equivalent to using precipitators with an efficiency of 99.5% with pulverized coal boilers. At the Labadie plant now under construction, Units 1 and 2 will utilize 700 ft. stacks with precipitators having an efficiency of 99.5%. For improved dispersion, Units 3 and 4 will have a common stack 700 ft. in height including the high efficiency precipitators.

Union Electric is presently evaluating the effectiveness of an SO_2 removal system on its Meramec No. 2 unit. This system, which is the first of its size in commercial operation in the United States and was put in service in late 1968, is said to remove 83% of the SO_2 from flue gases which would be equivalent to burning fuel with a 0.5% sulfur content. The system operates by air-injecting pulverized dolomite into the furnace where it reacts with part of the sulfur oxide. Once the dolomite reacts with the sulfur oxide, flue gases are passed through a scrubber where further reaction takes place with the sulfur oxide. The sulfur compounds that result from this reaction precipitate out as solids and are removed in the scrubber along with the fly ash. The solid residue is transferred to a settling tank where it is partially separated from the water and is finally conveyed to a disposal area. Utility officials feel that the system will not hinder the efficiency of the boiler, but operating costs will be higher because of the dolomite's cost and the need for higher powered gas fans that will be necessary to overcome pressure drops caused by the scrubber.

No governmental air pollution regulations other than city smoke ordinances currently exist in the service area of Northern States Power Company. The company, however, has taken voluntary action to provide control of the particulate emissions from generating plants. Electrostatic precipitators have been provided for every coal burning generating unit installed in the Twin City Metropolitan Area since 1942. In addition, 21 older coal burning boilers have been converted to gas and oil fuels. At its newest coal burning plant, 99% precipitators and a 785 ft. stack were installed to disperse gaseous wastes. To determine the effectiveness of these control measures at this plant, a network of nine monitoring stations was established in the area surrounding the plant. Continuous analyses of sulfur dioxide and soiling index are made, together with dust fall and cumulative sulfur dioxide determination. Wind direction and velocity are also

recorded at each station. To date, no significant deviations from predicted levels have been observed. To accomplish the above program NSP has invested about $8,000,000.

Advantage has been taken of the availability of dump natural gas to reduce the quantity of coal consumed. Also, because of the system maximum demand now occurring during the summer season the installation of gas turbines with gas-oil combination firing has proven to be attractive. To date 240 mw of gas turbines have been installed or committed for installation. In 1967, natural gas supplied about 40% of the total fuel requirements on the NSP system. This operation on gas and on light fuel oil affords a substantial reduction in sulfur dioxide as well as in particulate emission.

The State of Minnesota is presently holding hearings regarding proposed air regulations. Of great concern is the provision which severely limits SO_2 emissions in the Twin City Metropolitan Area. To comply with this will require either stack gas sulfur removal equipment or low sulfur fuels. Technological development of sulfur removal equipment is yet in its infancy and it is not practical to expect immediate large scale application to existing units. Low sulfur fuel does not appear to be an immediate solution because quantities of such fuel that can be burned in existing equipment are limited.

On the Minnesota Power and Light Company system, arrangements have been made to supply virtually all their present coal requirements and, more specifically, that for a 1973 350 mw generator unit with sub-bituminous coal from Montana. This coal has a heat content of 8750 Btu's/lb, and a sulfur content of less than one per cent. It will be transported via the longest unit train trip in existence consisting of a 1700 mile round trip between Colstrip, Montana and Cohasset, Minnesota. There will be four 100-car trains each week with each car carrying 120 tons.

Transmission Facilities

In late 1963 and early 1964, Mid-Continent Area Power Planners (MAPP) developed a comprehensive high voltage transmission program for its ten state upper midwest area. This program linked with 345 kv lines, the population centers of several major markets: Chicago, Milwaukee, Twin Cities, Sioux City, Omaha, Kansas City, Des Moines, Quad Cities and St. Louis. The lignite mine-mouth plants in western North Dakota were to be linked with 230 kv lines with eastern North Dakota and the Iron Range area of northern Minnesota. Construction of these transmission facilities will be essentially completed by 1972 at a cost of more than $250,000,000.

The Twin Cities-Milwaukee-Chicago 470 mile 345 kv line was completed and placed in service in May 1966. The circuit provides interconnection capacity for coordination among the Upper Mississippi Valley Power Pool, the Eastern Wisconsin Utility group, and Commonwealth Edison Company.

The 510 mile Twin Cities-Iowa-St. Louis 345 kv line was completed and placed in service in July 1967. It was constructed by seven members of the MAPP group, namely, Union Electric Company, Iowa Southern Utilities Company, Iowa-Illinois Gas & Electric Company, Iowa Electric Light & Power Company, Iowa Public Service Company, Interstate Power Company, and Northern States Power Company. This 345 kv interconnection will facilitate coordination among the Upper Mississippi Valley, Iowa and Illinois-Missouri Power Pools.

The Montgomery-Kansas City 345 kv line was constructed and placed in service in May 1968. This line was built by Union Electric Company and two companies in the South Central Region: Missouri Public Service Company and Kansas City Power and Light Company. The line, which is 280 miles long, is used to coordinate power exchanges between the Illinois-Missouri and the Mo-Kan Pools.

In 1969, the 220 mile Kansas City-Omaha 345 kv line will be constructed by Omaha Public Power District, St. Joseph Light & Power Company and the Kansas City Power & Light Company. Also in 1969, Iowa Power & Light Company will construct the 109 mile Des Moines-Hills, Iowa 345 kv line.

In 1970, the Omaha-Sioux City-Minneapolis 345 kv line will be constructed by Omaha Public Power District, Iowa Public Service Company, Interstate Power Company and Northern States Power Company.

Also in 1970, the Des Moines 345 kv line will be extended by Iowa Power & Light Company to Brownville, Nebraska, a distance of 150 miles. The Consumers Public Power District will construct a 345 kv line from Brownville to Hallam (near Lincoln) to Grand Island, a distance of 150 miles. This circuit will interconnect with the Fort

Thompson-Grand Island 345 kv line being built by the Bureau of Reclamation for service in 1970.

Other 1970 construction includes the Hills-Quad Cities 345 kv line which will be installed by Iowa-Illinois Gas & Electric Company to interconnect with the Quad Cities-Chicago 345 kv line to be built by Commonwealth Edison Company.

The program of 230 kv lines linking the lignite fields in North Dakota with western Minnesota and the Duluth-Twin Cities area will also be completed in 1970.

The Missouri Basin Systems Group started engineering studies in 1964 which included consideration of the regional 345 kv transmission program extending from Stanton, North Dakota south to Grand Island, Nebraska and east to Brownville, Nebraska where it would interconnect with other planned 345 kv transmission to the north, east and south. The 1964 study also considered a 345 kv transmission line between Stanton, North Dakota and Watertown, South Dakota. The plan included consideration of a 1.5 million kilowatts of additional nuclear, lignite and fossil-fueled capacity, and hydro peaking capacity. Several of the major elements of this plan are now being constructed by various agencies with the remaining elements under consideration for completion by 1975 or earlier.

In North and South Dakota and eastern Montana, the extensive 230 kv system of the U.S. Bureau of Reclamation has been augmented by the construction of additional 230 kv lines from the Corps of Engineers' hydroelectric station at Oahe Dam to New Underwood in South Dakota and thence to Stegall, Nebraska; in Montana from the Yellowtail hydroelectric project to Dawson County; and in South Dakota, from the Corps' hydro station at Big Bend Dam to Sioux Falls. In early 1970, the Bureau will have in operation a 345 kv line from Fort Thompson, near Oahe and Big Bend power plants in South Dakota, to Grand Island, Nebraska. The Bureau's system comprises the major part of the Joint Transmission System of the Missouri Basin Systems Group. The Joint System provides a means for coordinating system planning and operation of the Group and has provided the transmission outlet required to market the production from the Basin Electric Power Cooperative lignite-burning plant at Stanton, North Dakota. The system will be utilized also for seasonal exchanges of power between Nebraska and the MBSG systems in North and South Dakota, Montana, Iowa, Wyoming, Colorado and Minnesota.

Manitoba Hydro has started the first phase of major development of the Nelson River with 4–100 megawatt units now under construction at the Kettle Rapids generating site to be placed in service in 1971. Power from the Kettle Station will be delivered to Winnipeg over two ± 450 kv direct current transmission lines each about 600 miles long. The Nelson River, which flows from Lake Winnipeg to Hudson Bay, has the potential for development of five to six million killowatts of hydroelectric capacity. In 1970, a 145 mile 230 kv interconnection between Winnipeg, Manitoba and Grand Forks, North Dakota will be constructed by Manitoba Hydro, Northern States Power Company, Otter Tail Power Company, and Minnkota Power Cooperative, Inc. It appears that in the 1975–80 period a substantial tie, possible D.C., between Winnipeg, the Iron Range and the Twin Cities may be feasible to utilize about 800 megawatts of capacity from the Nelson River.

The easern part of the region is developing heavy concentrations of EHV facilities around St. Louis, Chicago, Milwaukee and the Minneapolis-St. Paul areas. In the Twin Cities area, for instance, a double circuit 345 kv loop is being built around the metropolitan area with completion scheduled for the latter part of 1969. A modular concept is being used in which the connected substation capacities are standardized to utilize the maximum capacity of the 345 kv lines, and to permit interchangeability of equipment. Within the loop, the existing 115 kv transmission network is being strengthened by utilizing existing overhead rights-of-way. Single circuit lines having capacity of 150 mva are being replaced with double circuit, bundled-conductor lines each having a capacity of 400 mva. By making maximum use of rights-of-way and by employing steel poles where aesthetics indicate, the impact of necessary overhead construction is being minimized until such time that underground facilities are technically and economically feasible.

The local EHV concentrations are being reinforced by EHV ties between the areas. A direct tie between the Chicago and St. Louis areas was completed this year by the installation of a 345 kv line between Kincaid Station (CECo) and Pana Substation (CIPSCo). Completion of the second unit at Quad-Cities Station (CECo and IIG&ECo) on the Mississippi River in 1971 will provide two 345 kv circuits eastward to the Chicago area and two 345 kv circuits to the west to supply the Quad-Cities area and tie into the 345 kv circuit extending

from St. Louis to Minneapolis. Also in 1971, CECo will install a 765 kv connection to the 765 kv system of the AEPCorp in Indiana. Later additions will extend this line around the northwest part of the Chicago Metropolitan area and west to Quad-Cities Station by 1980.

A pattern of transmission expansion for the region for the period through 1990 has been developed by the several pools and utilities comprising the region. Maps detailing this pattern are enclosed with this report. The expansion plan is complementary to the generation development and is designed to furnish outlet capacity for the generation facilities projected and a power supply to the loads projected, with the intent to provide a high degree of reliability consistent with the present system. This includes the ability to avoid uncontrolled system breakup and collapse even for remote contingencies. Calculation of specific severe disturbances was considered beyond the scope of the planning effort, however, a number of load flow calculations were made which served as a basis for judgment for the more severe conditions. These load flows for 1980, as an example, included total coincident delivery to Illinois and Wisconsin from outside sources of about 15% of the 1980 load in the receiving area. All inter-area tie capability was checked with at least one critical line out in the EHV transmission system.

At a minimum, it is intended to permit firm power purchases to be made, up to 50 percent of a system's largest unit, while providing for an operation which can withstand the loss of the largest unit while the highest capacity interconnection is out of service.

In general, the transmission system in the east is oriented to 345/765 kv voltage levels and that in the west is oriented to 230/500 kv. In both areas, the higher voltage chosen is related to the higher EHV voltage already committed in adjacent regions and reflects the classic two to one ratio of a superimposed transmission system. The specific developments shown also have been coordinated with those of the adjacent regions.

Figures 2 through 7 are intended to illustrate the level of intraregional and inter-regional transfer capacity for the 1970–1990 periods. The values shown in figures 2 and 5 for 1970 are based on MAIN and MAPP studies with each value estimated with other transfers at zero. To the extent that circulating current or power transfers between areas exist, the transfer capacities will be reduced. Capacities for subsequent periods are derived from adding to the 1970 levels aggregate values for subsequent additions according to this schedule which is intended to reflect the usually shorter length of lower voltage lines:

115/138 kv	100 mw
161 kv	150 mw
230 kv	200 mw
345 kv	300 mw
500 kv	600 mw
765 kv	1, 500 mw

It should be recognized that the resultant information is indicative only. No contingencies are provided for, no circulating current is recognized, an optimistic sharing of power flow is assumed, and a concurrency of application would be quite restrictive. Relatively precise transfer capacity values can be developed, but only for very specific conditions. To present such information in a simplified form would not be possible.

The extent of existing and projected EHV transmission facilities connecting the concentrated load areas is indicated in the following tabulation:

West Central Region—EHV Transmission, Total Circuit Mileages

Voltage kv	Miles
1970	
230	5, 800
345	2, 970
1980	
230	6, 620
345	6, 340
500	1, 250
765	570
1990	
230	6, 850
345	10, 600
500	2, 440
765	2, 170

General

The eastern and western portions of the West Central Region differ considerably one from another with respect to magnitude and distribution of load and distance between load centers. About 88 percent of the total peak load of the region in 1990 is in the area comprised of Illinois, Wisconsin, Minnesota, Iowa and northern Missouri and the remainder is the area which includes North and South Dakota, Nebraska and eastern Montana. The

opportunities for taking advantage of economy of size of generating units and extra high voltage transmission are related to the estimated amount of growth of the load and the magnitude of load of the separate areas making up the region.

The generating capacity reserves of 15.6% and 16.6% for 1980 and 1990 appear reasonable and compare favorably with determinations of probability studies which have been conducted by MAPP and by a number of utilities. These studies indicate regional reserves of 11% to be adequate to cover presently foreseen probabilities of forced outage.

Some opportunity utimately should exist between the West Central Region and adjacent regions for transfers of seasonal diversity power in addition to those now scheduled as evidenced by the forecasted loads for 1990 showing a regional winter peak about 18,500 megawatts less than the summer peak. At present, however, and seemingly for the near future, the surplus situation in the eastern part of the region during the winter is just adequate to permit maintenance to be accomplished. Because of the longer peak period involved, the orientation of the region to summer peaks decreases the time available for maintenance of generating equipment. This situation together with the reduced flexibility resulting from the proportionately larger generator units being projected will require in the eastern part of the region that the winter peak period be used significantly for generator maintenance. Further, the installation of peaking capacity which is designed for relatively short use and mainly on gas will operate against prolonged use during the winter period to enable sales of surplus power. However, to the extent that diversity effectively exists and is not required for maintenance and operating reserves it appears that the strengthened interconnections projected for the region will be capable of accomplishing any ensuing seasonal exchanges of power, including supplemental exchanges with the system of the Manitoba Hydro-Electric Board in Canada.

Emphasis is made here that the pattern of generating capacity and transmission facilities shown for the combined study areas indicates a possible trend rather than a blue print of future construction. Both the magnitude and characteristics of future load requirements will be subjected to strenuous marketing efforts aimed at providing electric energy for the region in a manner which will maximize the over-all benefits which are to be gained from this unique commodity. Similarly, the basic resources for supplying the required energy and the basic means for developing the energy will be subjected to prodigious efforts aimed at maximizing the utilization of national resources. In both areas, influences outside the industry will be substantial. Probably the one conclusion which can be stated with assurance is that actual expansion in the region no doubt will deviate in many ways from the plans presented here.

CHAPTER IV

COORDINATED PLANNING AND DEVELOPMENT

Structure of the Industry

Fifty-one interconnected systems currently generate approximately 95% of the energy consumed through electric utility service in the West Central Region. Table I below provides 1967 data as to number and size of these major utilities in the various ownership segments of the industry. This group generally can be described as consisting of those systems providing virtually all of the high voltage system facilities in this region.

1967 load and capacity data for the individual major utilities in each ownership segment are shown in Appendix A.

In addition to these major utilities there are about 1,000 other utility entities involved in generation and/or distribution of electric energy. These are identified as to type of ownership, size and general location in Appendix B.

Trends in the Development of Coordination Mechanisms

At present, nine coordinating organizations function within the region as follows:

Wisconsin Public Service Corporation-Wisconsin Power and Light Company-Madison Gas and Electric Company Pool
Wisconsin-Upper Michigan Systems
Illinois-Missouri Pool
Iowa Pool
Mid-America Interpool Network
Mid-Continent Area Power Planners
Missouri Basin Systems Group
Nebraska Public Power System
Upper Mississippi Valley Power Pool

Coordination areas of these organizations are shown in Figures 1–3. Appendix C presents first a brief summary and then detailed information on each body and its structure, purposes, and activities.

It is emphasized that there are no particular discontinuities in the pattern of interconnections at the boundaries of these organizations. Numerous other interconnection agreements and inter-relations exist that provide mechanisms for liaison and continuity in coordination across the region as demonstrated by the examples enumerated below:

1. MAIN and MAPP have overlapping membership with eight utilities being members of both of these organizations. This liaison arrangement is deemed particularly desirable for close coordination in planning and operation along the recently completed Twin Cities-Milwaukee-Chicago-St. Louis-Twin Cities 345 kv loop. Operation of this loop and all other interconnecting transmission lines, and those otherwise mutually affected, is provided through established operating committees, through system simulation operating studies, and through continuous liaison between the respective coordination offices. The studies consist of

TABLE I

Type of ownership	Utilities	Non-Coincidental peak load (MW)	Gen cap (MW)	Energy prod (1,000 MWH)
Investor-owned	25	22, 954	26, 032	118, 566
Rural electric G &T cooperatives	19	1, 657	1, 382	5, 646
State	6	1, 461	1, 120	4, 226
Federal	1	746	2, 048	9, 692
Total	51	26, 818	30, 582	138, 130

current year operating studies, transfer capacity studies, and extreme disturbance studies. The areas of coordinated planning are handled through the planning arms of each of the organizations. Much of the planning is based upon the aggregate load and capability forecasted and includes not only consideration of new facilities but also the future use of the interconnecting transmission facilities and power transactions to effect optimal use of generating equipment.

2. MAPP and MBSG liaison on projects of mutual interest is handled through the Intersystem Coordinating Committee. This committee was established by the respective organizations in 1965. Prior to the establishment of the MAPP Coordination Office and the associated Coordinating Committee, the Intersystem Committee organized an interim task force to review relay operating practices to assure that relaying of mutual interest would provide a reliable operation. Progress has been slow in the area of joint planning of transmission and generation and the committee itself has recently proposed that its parent organizations reconsider its membership and better define its responsibilities in the interest of improving progress.
3. All members of the Iowa Pool and UMVPP belong to the MAPP organization and have thereby broadened their capabilities in the traditional pooling activities of coordinated planning of generation and transmission, including power transactions, and coordinated operation of generation and transmission including short and long term maintenance scheduling, economy energy interchange, voltage profiles, automatic under-frequency load shedding, and dispatching procedures. This broadening comes about through the overview afforded in considerations of the Planning Committee which is geographic in its representation and through participation in the Coordinating Committee associated with the Coordination Office.
4. All members of the Wisconsin Power Group and Illinois-Missouri Pool belong to the MAIN organization.
5. MAPP-MAIN-UMVPP-Iowa Pool Liaison, together with USBR participation in the MAPP Coordination Center, has resulted in development of an extensive teletype communication system permitting broad area coordination on day to day operating matters.

   The area is presently served by three teletype systems, all of which employ rented telephone company facilities. Cost sharing varies in each of the three systems ranging from equal shares to formulas using both number and size of systems involved. Teletype stations are located in the dispatching offices of the participating systems and the coordination centers. Use is limited to exchange of operating information and weather information.

   The present systems are:

   MAIN 15 terminals—5 in Wisconsin, 4 in Illinois—2 in Minnesota (MAPP & NSP), 2 in Missouri (UE & AEC), 1 in Little Rock, Arkansas (SCEC) 1 in Canton, Ohio (AEP ECAR)

   UMVPP 10 terminals—1 in North Dakota, 1 in South Dakota, 6 in Minnesota, 1 in Wisconsin, 1 in Iowa

   USBR 1 in South Dakota

   IOWA POOL 10 terminals—2 in Minnesota (MAPP & NSP), 7 in Iowa, 1 in St Louis, Missouri (UE)

   The UMVPP and Iowa Pool systems will be replaced in April 1969 by one MAPP system containing 25 terminals. This will include the present terminals plus new terminals for other MAPP members and adjacent utilities. The system will be comprised of 2 terminals in North Dakota, 6 terminals in Minnesota, 2 in Wisconsin, 2 in South Dakota (including USBR), 8 in Iowa, 2 in Nebraska (OPPD and CPPD), and 3 in Missouri (UE, St Joseph L&P and KCP&L). The MAPP system will utilize 100 wpm teletypes under the control of an automatic polling device located in the MAPP Center. All transmission will be by punched tape except during emergencies when an emergency override will permit manual transmission. Cost sharing will be according to a formula intended to recognize size of systems, mileage between adjacent terminals, and benefits accruing equally regardless of size.
6. As planning of specific facilities reaches a point in progress where the coordinating

organization is agreed on the basic function and design, the participating utilities are represented on a number of task forces having responsibility for design, contractual arrangements, and use. The task force membership straddles organizational lines and provides further opportunities for coordination of associated facilities.

Projections of Future Coordinating Requirements

The following discussion of possible future organizational arrangements among electric utilities is in reference to the fifty-one systems identified in Section I as providing 95% of the electric service in the region. It is, of course, recognized that corporate consolidations will very likely reduce the number of separate entities in the future. However, there is no basis for predicting the specific patterns or timing such consolidations may follow other than a general reference to those already announced to be under study.

By 1970, MAPP intends to increase the coordination among the various parts of the MAPP organization, including the Iowa Pool, the UMVPP, and its Nebraska members by developing a super-pool agreement. This consolidation will result in these five sub-regional systems remaining as workable coordinating entities within the West Central Region:

- Commonwealth Edison Company
- Eastern Wisconsin Utilities (including the Upper Peninsula)
- Illinois-Missouri Pool (including Central Illinois Light Company)
- Mid-Continent Area Power Planners
- Missouri Basin Systems Group

Each of these systems will exercise primary responsibility for planning and operation within their area, particularly with respect to economic matters.

With regard to reliability-oriented coordination, MAIN would continue with its present inter-pool operation in the eastern part of the region. Reliability-oriented coordination for the western portion of the region is expected to be provided by the recently executed Mid-Continent Area Reliability Coordination Agreement either expanded to include MBSG members or through liaison arrangements with a separate MBSG reliability group.

Future patterns of generation and transmission developments prepared by the WCRAC contemplate 765 kv and 500 kv transmission lines across the region in the 1980's. These lines will provide capacity for meaningful power exchanges on a region-wide basis and also increase the interdependency among systems, particularly with respect to reliability. It is therefore proposed that a single West Central Reliability organization be established by 1980. In view of the large number of systems involved, manageability considerations dictate an interpool-type organization such as MAIN with the five above-identified area systems as members.

The foregoing material relating to future coordination patterns has been presented at meetings of the MAIN, MAPP and MBSG organizations in an effort to solicit views of utilities not represented on the WCRAC.

Problems and Solutions

Operation of an electric power system is a complex matter involving the consideration of innumerable electrical elements and many people. Taken as a whole, the configuration changes from season to season, from day to day, and from hour to hour. To operate all of the interconnected electrical systems within a region in a truly coordinated manner becomes a tremendously complex matter requiring knowledgeable people, the necessary equipment and communications for the required overview, and of equal importance a strong desire on the part of all of those so engaged. That this coordination can be accomplished, and must be accomplished, is fully appreciated and has been taken on as a challenge of considerable substance by the utilities in this region.

It is recognized that the true strength of the operation is in the local knowledge of each area's needs and the resources available to supply these needs. The requirement then is for a coordinating effort which will supply the involvement necessary to do the job but which will not unnecessarily interfere in operations that can be adequately handled locally. Furthermore, it cannot be expected that a coordinating effort can be arbitrarily overlaid on the existing operation. Instead a coordination evolution is required which will gradually develop the capability of the coordinating organization and, in turn, the confidence of the participating systems with a resultant growing willingness to accept the decisions and judgment of the coordinating personnel and to encourage their efforts.

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Within the West Central Region there are variations in the nature of systems and load densities across the region producing differences in coordination problems and requirements. For example, a relatively few systems along the eastern edge of the region (Eastern Wisconsin Utilities, Commonwealth Edison, and the Ill-Mo Pool) generate almost 60% of the region's requirements while serving 15% of its area. As a result, pooling and interconnection arrangements appropriate for this area are markedly different than those applicable to the large number of systems serving the remainder of the region. Many types of utilities are represented with varying characteristics including that of size and of financing within the major groupings. Because of the hour-to-hour vital need to have a reliable operation, the coordinated operation of these systems has proven to be an endeavor not significantly affected by this dissimilarity. In the area of planning, substantial strides have been made in coordinating planning of both generation and transmission. As previously noted, only MAPP and MBSG have yet to fully coordinate their efforts. This situation is recognized by both organizations and is under active consideration.

Interregional Coordination

There are two formal arrangements for interregional coordination identified as such. These are the liaison arrangement between MAIN and ECAR, and MAIN and MAPP membership in the National Electric Reliability Council. Beyond these there are numerous bilateral interconnection agreements and other established channels for coordinated planning and operation with electric systems in adjacent regions.

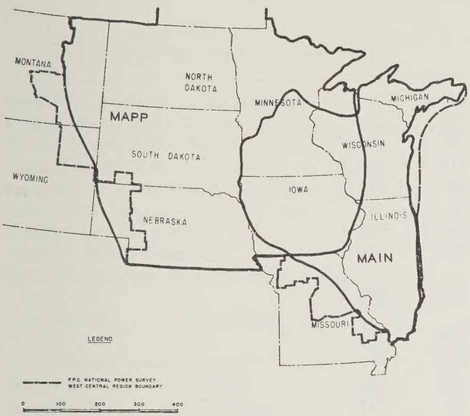
The USBR has membership in both the Western Systems Coordination Council (WSCC) and the MAPP Coordination Committee and MAPP operating representatives attend WSCC operating meetings. These arrangements, along with these inherent within the USBR, provide liaison with the west lying region.

Some multi-system coordination activities involving other regions are: The MIIO Agreement among Commonwealth Edison and five major utilities in Indiana and Michigan, which, among other returns, resulted in system performance studies in depth which included Commonwealth Edison Company as a participant and enveloped the eastern portion of this region; The Twin Cities-Kansas City 345 kv Coordinating Agreement among four MAPP members and Kansas City Power and Light Company and St. Joseph Light and Power Company in the South Central Region, which provides for the exchange of power and energy with the aim of optimizing the utilization of generation and bettering reliability; and the East-West Tie Closure Task Force, which was formed for the express purpose of studying the feasibility of and the procedures for closing the Bureau of Reclamation ties between the eastern and western portions of its Missouri River Basin system, and hence interconnecting the western region systems to the remainder of the U.S. interconnected systems.

The Manitoba Hydro Electric Board, although not yet interconnected with United States systems, participates in planning activities through its membership in the MAPP organization. As a result, negotiations for the 1970 construction of a Winnipeg-Grand Forks 230 kv interconnection have now been completed and construction and operating contracts signed. This interconnection will have a capacity of about 200 mw although it is being initially regarded as having a nominal 100 mw capacity for purpose of scheduling power and energy. This interconnection will provide Manitoba Hydro with interconnected operation with the U.S. systems, will make unnecessary the construction of thermal capacity, will provide a market for future excess power and energy, and will provide a source of energy during dry years. For the U.S., a power supply will be provided which is diversified in the source of the power and has prompt availability. The seasonal load diversity will permit mutually advantageous seasonal power exchanges and the reliability on either side of the boundary will be improved from the improved diversity overall. No unusual problems have been encountered in its planning even though the facility is being installed by such diverse interests as two investor-owned utilities and one G & T cooperative on the U.S. side, and by a Canadian Crown Corporation on the Canada side. Feasibility studies for a second 230 kv interconnection between Manitoba and the Garrison, North Dakota area are scheduled to be undertaken jointly by Manitoba Hydro and a number of MAPP and MBSG members.

WEST CENTRAL REGION COORDINATION AREAS

MID-CONTINENT AREA POWER PLANNERS
MID-AMERICA INTERCONNECTED NETWORK

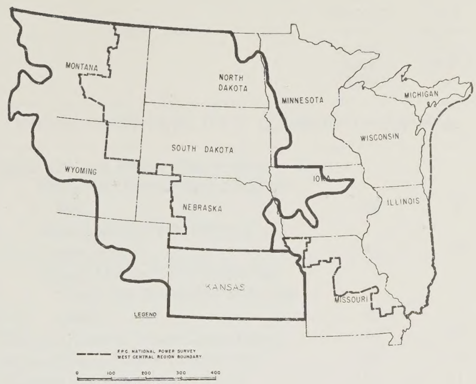


Boundaries indicate general areas and do not necessarily include all systems within an area.

FIGURE 1

WEST CENTRAL REGION COORDINATION AREA

MISSOURI BASIN SYSTEMS GROUP

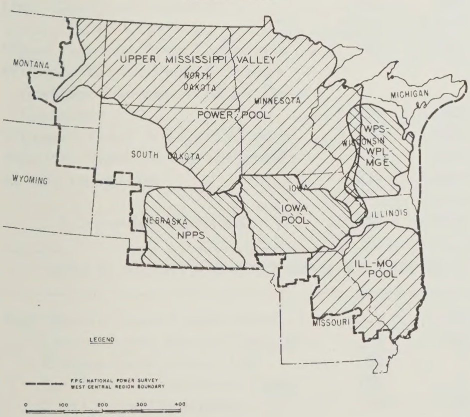


Boundaries indicate general areas and do not necessarily include all systems within an area.

FIGURE 2

WEST CENTRAL REGION OPERATING AREAS

UPPER MISSISSIPPI VALLEY POWER POOL
WPS-WPL-MGE POOL
IOWA POOL
NEBRASKA PUBLIC POWER SYSTEM
ILL-MO POOL



Boundaries indicate general areas and do not necessarily include all systems within an area.

FIGURE 3

APPENDIX A

DATA ON MAJOR UTILITIES

Utility Name	1967 calendar year peak load (MW)	Jan. 1, 1968 capability (MW)
INVESTOR-OWNED UTILITIES		
Black Hills Power & Light Company	94	110
Central Illinois Light Company	474	545
Central Illinois Public Service	868	1, 178
Commonwealth Edison Company	7, 643	8, 547
Consolidated Water Power Company	96	36
Edison Sault Electric Company	48	58
Illinois Power Company	1, 338	1, 444
Interstate Power Company	329	564
Iowa Electric Light & Power Company	472	436
Iowa-Illinois Gas & Electric Company	452	415
Iowa Power & Light Company	497	633
Iowa Public Service Company	312	421
Iowa Southern Utilities Company	175	92
Lake Superior District Power Company	91	108
Madison Gas and Electric Company	188	211
Minnesota Power & Light Company (includes Superior Water, Light & Power Co.)	482	511
Montana-Dakota Utilities Company	157	207
Northern States Power Company (includes Northern States Power Co-Wisconsin)	2, 323	2, 232
Northwestern Public Service Company	98	73
Otter Tail Power Company	192	280
Union Electric Company	3, 212	3, 053
Upper Peninsula Power Company	95	125
Wisconsin Electric Power Company (includes Wisconsin-Michigan Power Company)	1, 924	2, 422
Wisconsin Power & Light Company	620	658
Wisconsin Public Service Corporation	539	653
Electric Energy, Inc [1]	235	1, 020
Investor-owned subtotal	22, 954	26, 032
RURAL ELECTRIC G&T COOPERATIVES		
Basin Electric Power Cooperative [2]		216
Central Power Electric Coop, Inc.	68	38
Dakotas Electric Coop, Inc	52	9
East River Electric Power Coop	135	0
L&O Power Cooperative	18	0
Basin Electric Power Cooperative [2]—Con.		
Northwest Iowa Power Cooperative	82	0
Rushmore Electric Power Cooperative	41	0
Upper Missouri G&T Electric Coop (WCR portion of 45 mw total)	33	0
Central Electric Power Cooperative	74	65
Central Iowa Power Cooperative	126	124
Cooperative Power Association	196	11
Corn Belt Power Cooperative	100	116
Dairyland Power Cooperative	283	305
Eastern Iowa Light and Power Coop	34	65
Minnkota Power Cooperative, Inc	123	45
Northeast Missouri Electric Power Coop	65	22
Southern Illinois Power Cooperative	50	99
United Power Association (Includes RCPA and NMPA)	157	233
Western Illinois Power Coop, Inc	20	34
G&T subtotal	1, 657	1, 382
STATE SYSTEMS		
Consumers Public Power District	400	120
Nebraska Public Power System, includes	407	145
The Central Nebraska Public Power and Irrigation District		162
Platte Valley Public Power and Irrigation District		26
Loup River Public Power District		40
Omaha Public Power District	654	627
State subtotal	1, 461	1, 120
FEDERAL SYSTEMS		
U.S. Bureau of Reclamation-Department of the Interior	746	2, 048
WCR grand total	26, 818	30, 582

[1] Owned jointly by Central Illinois Public Service Co., Kentucky Utilities Co., Illinois Power Co., and Union Electric Co. The 235 mw is AEC load in Kentucky. Surplus capacity is shared by the four owning companies.

[2] Supplies power to members over and above USBR firm hydro allocations.

APPENDIX B

STRUCTURE OF THE ELECTRIC UTILITY INDUSTRY

The 1965 FPC Form 12 reports show a total of 1,049 electric systems involved in supplying energy to ultimate consumers in the West Central Region. There are five distinct ownership segments: investor-owned, rural electric cooperatives, municipally-owned, state-owned, and federal agencies. Statistics as to size and number of utilities in the various ownership segments in the region are tabulated below:

TABLE I

Type of ownership	Number of systems			Generating capacity (KW)	Percent of total	Energy production (1,000 KWH)	Percent of total
	Total	Owning generation	Distributing only				
Municipal	669	323	346	2, 102, 874	6. 9	4, 553, 454	3. 6
REA	261	24	237	851, 317	2. 8	3, 374, 277	2. 6
Investor-owned	85	55	30	24, 200, 710	80. 1	106, 967. 267	83. 8
Federal	2	2	0	1, 891, 235	6. 3	8, 586, 157	6. 7
State	32	7	25	1, 178, 509	3. 9	4, 157, 147	3. 3
Total	1, 049	411	638	30, 224, 645	100. 0	127, 638, 302	100. 0

Similar statistics applicable to each of the FPC Power Supply Areas are given in Table II.

Table III attached lists the generating capacity and number of electrically isolated systems in the region. Of the 71 such systems, 70 are municipal utilities and one is a rural electric cooperative.

The above statistics are misleading from the point of view of the number of entities involved in coordinated planning and development in the West Central Region. As noted in the statistics themselves, 638 of the 1,049 systems are only concerned with distribution and hence not involved in bulk power supply matters. Similarly, many of the remaining 411 systems that own generation depend upon imports from interconnections for a large part of their power supply. The remaining comments of this memorandum have to do with statistics on systems owning generation.

Of the 323 municipal systems owning generation, 253 operated interconnected with the major utility system serving their area. Only 29% of these interconnected municipals generated as much as one-half of their own consumer requirements in 1965.

The number of rural electric cooperatives owning generation is out of date since some of the individual distribution cooperatives that own generation have since been consolidated with rural electric G&T systems.

The 55 investor-owned utilities include industrial plants and small subsidiaries of larger companies. There are also a number of very small systems with hydro or diesel plants carried over from a by-gone era that are now essentially distribution agencies. It appears that there are 25 investor-owned systems with primary responsibility for bulk power supply in this segment.

The two federal systems are the large USBR Missouri Basin Project and a very small federal installation at Sault Ste Marie, Michigan.

The state-owned power systems are located principally in Nebraska. Three other such systems supply state universities, two in Iowa and one in Illinois.

TABLE II

WEST CENTRAL REGION—1965

Type of ownership	Number of systems: Total	Owning generation	Distributing only	Generating capacity (% of total)	Energy production (% of total)
PSA 13:					
Municipal	81	26	55	0. 683	0. 450
REA	15	3	12	0. 035	0. 005
Investor-owned	25	18	7	13. 370	13. 683
Federal	1	1	0	0. 061	0. 126
Total	122	48	74	14. 149	14. 264
PSA 14:					
Municipal	14	6	8	0. 457	0. 323
REA	3	0	3	0. 000	0. 000
Investor-owned	5	4	1	26. 081	27. 733
Total	22	10	12	26. 538	28. 056
PSA 15:					
Municipal	39	24	15	0. 645	0. 289
REA	13	3	15	0. 270	0. 506
Investor-owned	10	3	7	8. 700	8. 294
Total	67	30	37	9. 615	9. 089
PSA 16:					
Municipal	110	56	54	1. 075	0. 497
REA	59	4	55	1. 176	1. 358
Investor-owned	17	8	9	8. 799	9. 400
Total	186	68	118	11. 050	11. 255
PSA 17:					
Municipal	188	99	89	1. 701	0. 918
REA	70	4	66	0. 662	0. 458
Investor-owned	11	9	2	7. 038	6. 740
State	2	2	0	0. 072	0. 074
Total	271	114	157	9. 473	8. 190
PSA 40:					
Municipal	37	24	13	1. 000	0. 614
REA	26	2	24	0. 369	0. 209
Investor-owned	7	4	3	13. 775	16. 161
State	1	1	0	0. 099	0. 074
Total	71	31	40	15. 243	17. 058
PSA 26:					
Municipal	44	24	20	0. 290	0. 027
REA	28	5	23	0. 297	0. 108
Investor-owned	3	3	0	1. 009	0. 791
Total	75	32	43	1. 596	0. 926

TABLE II—Continued

Type of ownership	Number of systems			Generating capacity (% of total)	Energy production (% of total)
	Total	Owning generation	Distributing only		
PSA 27:					
Municipal	18	12	6	0. 072	0. 008
REA	42	3	39	0. 008	0. 000
Investor-owned	5	4	1	1. 296	1. 002
Federal	1	1	0	6. 196	6. 601
Total	66	20	46	7. 572	7. 611
PSA 28:					
Municipal	138	52	86	1. 034	0. 441
REA	0	0	0	0. 000	0. 000
Investor-owned	2	2	0	0. 002	0. 001
State	29	4	25	3. 728	3. 109
Total	169	58	111	4. 764	3. 551
Total 9 PSA's:					
Municipal	669	323	346	6. 957	3. 567
REA	261	24	237	2. 817	2. 644
Investor-owned	85	55	30	80. 070	83. 805
Federal	2	2	0	6. 257	6. 727
State	32	7	25	3. 899	3. 257
Total	1, 049	411	638	100. 000	100. 000

TABLE III

ISOLATED SYSTEMS

	Number of systems	Capacity (KW)	Generation (1,000 KWH)
PSA 13	3	38, 695	71, 860
PSA 14	5	87, 880	189, 289
PSA 15	5	18, 022	33, 984
PSA 16	5	19, 149	32, 162
PSA 17	15	45, 191	94, 374
PSA 26			
PSA 27			
PSA 28	23	76, 348	129, 087
PSA 40	15	86, 067	177, 993
Total	71	371, 352	728, 749
Total utility industry (including isolated systems)	1, 049	30, 224, 645	127, 638, 302
Isolated systems as percent of total	6. 77	1. 23	0. 57

APPENDIX C

COORDINATING ORGANIZATIONS

The power suppliers in the West Central Region to some degree have been coordinating the planning, construction, utilization and operation of generation and transmission facilities since the early 1940's. This coordination has been between suppliers both within and outside the West Central Region. In the earlier days coordination was on an informal basis. This approach eventually was replaced by pooling agreements. Then as systems grew and generation and transmission technology advanced, large regional power planning groups developed. The resultant coordinating organizations are described here in summary and in detail in following separate reports.

The three major regional power planning groups in the West Central Region are the Missouri Basin Systems Group (MBSG), the Mid-Continent Area Power Planners (MAPP), and Mid-America Interpool Network (MAIN). One additional planning group is the Wisconsin-Upper Michigan Systems which was known as the Wisconsin Planning Group from its organization in May 1963 until 1968. This group now includes utilities in Eastern Wisconsin and the Upper Peninsula of Michigan. The group performs functions for those utilities which have interconnections which are of major significance to the entire eastern Wisconsin and Upper Michigan region. Planning is coordinated with other utilities through participation by all of its members in MAIN.

All members of the Wisconsin-Upper Michigan Systems are members of MAIN, certain members of MAIN belong to MAPP and certain members of MAPP to MBSG. Also, there are members of each of these groups who hold membership in regional groups outside of the West Central Region. This overlapping participation aids in the overall planning and coordination of the generation and transmission facilities in this large geographic segment of the United States.

The Missouri Basin Systems Group (MBSG) was established by the Missouri Basin Pooling Agreement in January 1963. It is concerned with both regional planning and with a pooled operation. MBSG is composed of the U.S. Bureau of Reclamation and a large number of municipals, rural cooperatives, and public power districts in eight states. Its objectives are to achieve coordinated planning for provision of the major power facilities required including thermal generation and high voltage transmission to meet the growing needs of the Systems Group members beyond those met by the Federal hydro system, and to provide for coordinated operation of the wholesale power supply system.

Mid-Continent Area Power Planners (MAPP) was organized in February 1963. Its purpose is to promote integrated regional planning, to improve the quality and cost of service to the customers of its members, and to coordinate operation of the bulk power supply. To aid in effecting reliability and economy, a coordination center has been established in Minneapolis. MAPP membership has been growing and at the present time, consists of 15 investor-owned utilities, 8 rural electric generation and transmission cooperatives, 2 public power districts, 28 municipal systems, and the Manitoba Hydro-Electric Board of Canada. The Bureau of Reclamation participates in the operations of the MAPP Coordination Center.

In November 1964 the Mid-America Interpool Network (MAIN) was created. Members are assigned to one of seven groups for representation at meetings. These groups, which are formed along the lines of the pool membership of the various companies, are the Commonwealth Edison Company, Illinois Group, Missouri Group, Eastern MAPP Group, Wisconsin-Upper Michigan Systems, Indiana Group, and the American Electric Power Group. The last two groups are companies with liaison membership, primarily associated with ECAR. MAIN's purpose is to promote regional coordination of the planning, construction, and operation of the members' generating and transmission facilities. Emphasis is on reliability and economy. MAIN operates a coordination center in Chicago for day-to-day coordination.

Each of the three regional groups has completed a considerable number of engineering studies. In addition to these studies on reliability, transmission capability, and operations, items coordinated include the forecast of load and generation, relay settings, load shedding, communications, maintenance, spare parts and material availability, and education programs.

The achievements of these groups include scheduling of diversity interchange, coordinated EHV transmission networks, economy by delaying installation of generating units and also increasing the size of some units, participation in large plant construction and other improvements.

In the West Central Region there are six power pools. These pools, organized under specific agreements, consist of power suppliers that are interconnected and have agreed to a coordinated approach to improve economy and service for their combined loads. Coordinated planning and operation provides for sharing of generating reserves including spinning reserves, coordinated generation and transmission development, joint scheduling of maintenance, and power and energy transactions. Included in these transactions are short term and long term power contracts, emergency and maintenance energy, and economy energy. The six pools are: the Nebraska Public Power System, the Illinois-Missouri Pool (Ill-Mo), the Iowa Pool, the Wisconsin Public Service—Wisconsin Power & Light—Madison Gas and Electric Pool (WPS–WPL–MGE), the Upper Mississippi Valley Power Pool (UMVPP), and the Missouri Basin Systems Group (MBSG).

The Nebraska Public Power System has participated in coordinated planning and operations since 1941. The System presently coordinates and dispatches the operation of the generation and transmission facilities of the following public power and irrigation districts in east-central Nebraska: Loup River, Platte Valley, Central Nebraska, and Consumers. In addition, the System serves as the control area for 22 municipal and state agencies. Through various members, it participates in MBSG and MAPP.

The Ill-Mo Pool was created in 1952 by Central Illinois Public Service, Illinois Power, and Union Electric, who function on a single system basis for daily operation and long-range facility planning. Through an agreement with Illinois Power, Central Illinois Light is provided some degree of coordinated planning and operation. The pool is represented in both MAIN and MAPP.

The Iowa Power Pool originally was formed in 1958. A successor agreement became effective January 1, 1969. The members are Corn Belt Power Cooperative, Iowa Electric Light and Power Company, Iowa-Illinois Gas and Electric Company, Iowa Power and Light Company, Iowa Public Service Company and Iowa Southern Utilities Company. The members participate in coordinated planning of generation and transmission facilities and coordinate daily operations. The Pool is represented in MAPP and MAIN.

The WPS-WPL-MGE Pool consists of Wisconsin Public Service, Wisconsin Power & Light, and Madison Gas & Electric. The original pool was formed in December 1960 and was joined by MGE in March 1968. The members participate in joint planning and operation of generation and transmission facilities and the purchase and sale of capacity and energy. Members participate in MAIN.

The Upper Mississippi Valley Power Pool is a planning and operating pool which carries out coordination under a formal agreement. Six utilities formed the original pool in February 1961. They are Dairyland Power Cooperative, Minnesota Power and Light Company, Northern States Power Company (Minn) and its subsidiary, Northern States Power Company (Wisc), Interstate Power Company, and Otter Tail Power Company. The original agreement has been amended to provide for memberships of eight additional utilities and the pool now has members in Wisconsin, Minnesota, Iowa, North and South Dakota, and Montana. All members belong to MAPP and certain members to MAIN.

The Missouri Basin Systems Group is an operating pool whose members belong to the MBSG. Day-to-day operations are conducted by the Bureau of Reclamation's control center at Watertown, South Dakota.

Commonwealth Edison is a large power supplier, equal in size to several of the formal pools. While not a member of a formal pool it is interconnected directly or indirectly with a number of pools as well as other large systems such as American Electric Power to the east. Through its numerous interconnection contracts it effects interchange economies and capacity sharing with its neighbors. Planning and coordination for reliability as well as economies with other pools is primarily effected through membership in the MAIN organization.

Eastern Wisconsin and Upper Peninsula Companies

The companies included in this report are as follows:

1. Edison Sault Electric Company (ESE)
2. Madison Gas and Electric Company (MGE)
3. Wisconsin Electric Power Company (WEP)
4. Wisconsin Michigan Power Company (WMP)
5. Wisconsin Power and Light Company (WPL)
6. Wisconsin Public Service Corporation (WPS)
7. Upper Peninsula Power Company (UPP)

Wisconsin Power and Light Company—Wisconsin Public Service Corporation—Madison Gas and Electric Company Pool

1. Type of Organization:

The WPS–WPL–MGE Pool is a planning and operating pool.

2. History of Development:

June 2, 1953	First major direct interconnection between WPS and WPL constructed between Oshkosh and Fond du Lac, Wisconsin.
December 29, 1960	WPS and WPL completed a Power Pool Agreement which established the terms for joint planning and operation of their respective power generation and transmission facilities.
December 1, 1963	WPS commenced the purchase of Participation Capacity from WPL and thereby caused an equalization of percent reserves for the two participants.
December 1, 1964	WPS placed in operation the first jointly planned capacity addition.
March 11, 1968	New Power Pool Agreement completed making MGE a Pool member.

NOTE.—Subsequent agreements have resulted in joint purchases and sales of capacity between the pool and non-participants and development of joint plans for other capacity additions.

3. List of Members:

	1967 peak load (MW)	*Jan. 1, 1968 capability (MW)*
Wisconsin Public Service Corporation	539	653
Wisconsin Power and Light Company	620	658
Madison Gas and Electric Company	188	211
Total	1, 347	1, 522

4. Requirements for Participation:

The participants have not established specific requirements for membership in this pool although, in general terms, it is agreed that participants must be of a size to install large generating units and must participate in the ownership of major interconnecting facilities.

5. Organizational Structure Including Official Positions, Committees and Their Functions and Methods of Arriving at Decisions Affecting Members of the Coordinating Group:

An Operating Committee consisting of two members from each participating company is charged with the administration of the pooling agreement. This committee does, among other things:

(*a*) Establish operating and maintenance schedules and control and operating procedures.
(*b*) Assign spinning reserve requirements.
(*c*) Establish limits for reactive kva requirements.
(*d*) Review capacity and demand data and recommend capacity additions.
(*e*) Establish ratings of capacity sources.
(*f*) Establish capacity purchases required to equalize reserves.

The Operating Committee can and does develop rules and procedures for administration of the pool. Recommendations to install new capacity and to purchase or sell capacity to nonparticipants must be approved by the presidents of the participating companies.

6. Practices in the Planning and Development of Facilities:
   (*a*) Each participant makes its own load projections. These projected loads are added together to determine expected pool demands. There is little diversity between participants' loads.
   (*b*) The pool procedures require that the participants will equalize percentage reserves by purchase and sale of participation capacity.
   (*c*) Pool participants coordinate stability studies with nonparticipants through the Wisconsin-Upper Michigan Systems organization.
   (*d*) The participants stagger capacity additions to maintain a reasonable balance between capacity and demand on each system.
7. Operating Practices:
   (*a*) The participants buy and sell various types of capacity and energy which are identified as: participation capacity, short term power, contract energy, emergency energy, economy energy, and maintenance energy.
   (*b*) Total reserve requirements for the pool are determined by the Operating Committee and allocated to participants as stated in 6B.
   (*c*) Maintenance is coordinated with other utilities in Eastern Wisconsin.
   (*d*) Each participant maintains its own system operating center and economic dispatch equipment. Economy energy is interchanged to achieve total operating economy for the pool.

Wisconsin-Upper Michigan Systems

1. Type of Organization:
   Wisconsin-Upper Michigan Systems is made up of four active committees: Executive, Coordinating, Engineering and Operating.
2. History of Development:
   On May 27, 1963, the Wisconsin Planning Group was initiated by a Memorandum of Intent. The original participants in the Planning Group were Wisconsin Electric Power Company, Wisconsin Michigan Power Company, Wisconsin Public Service Corporation, and Wisconsin Power and Light Company. In 1964, Madison Gas and Electric Company joined the Wisconsin Planning Group. In 1968 the name was changed to Wisconsin-Upper Michigan Systems and Upper Peninsula Power Company became a member.
3. List of Members:

	1967 peak load (MW)	*Jan. 1, 1968 capability (MW)*
Wisconsin Electric Power Company	1, 924	2, 422
Wisconsin Michigan Power Company	[1] 401	[1] 105
Wisconsin Public Service Corporation	539	653
Wisconsin Power and Light Company	620	658
Madison Gas and Electric Company	188	211
Upper Peninsula Power Company	95	125
Total	3, 366	4, 069

[1] Included in WEPCo totals.

4. Requirements for Participation:
   (*a*) Suppliers must own and operate substantial amounts of generating capacity.
   (*b*) Suppliers must have a high capacity interconnection (115 kv or above) with another member of WUMS and have operations which are significant to the reliability of the interconnected system of the region.

(*c*) Suppliers must own or participate in the operation of an up-to-date system operating center which contains the facilities to control generation and interconnection tie line energy flows and has adequate intercompany and intracompany communication facilities.

(*d*) Suppliers shall be located in Wisconsin, Upper Michigan or in a contiguous territory to and directly interconnected with one of the members of WUMS.

5. Organizational Structure:

Wisconsin-Upper Michigan Systems is made up of four committees: Executive, Coordinating, Engineering and Operating. The committees actively coordinate studies of joint planning and operating problems. Planning studies usually result in recommendations to the managements of the several companies. The committees have been very successful in achieving coordination among the several companies. Coordination with other utilities outside WUMS was originally achieved through the Joint Planning Committee which included representatives of Northern States Power Company and Commonwealth Edison. The Joint Planning Committee, although still in existence, has been generally supplanted by the MAIN organization. Deliberations of the MAIN Engineering and Operating Committees are reported at meetings of WUMS committees.

6. Practices in the Planning and Development of Facilities:

(*a*) Coordinated load projection—Each participant makes its own load projection. These projected loads are summarized to determine expected region demands. There is no significant diversity between participant's demands.

(*b*) There is no fixed percentage minimum reserve established for WUMS because the requirements of individual utility service areas and the characteristics of generating units in various utilities differ and thus dictate slightly different reserve requirements. WUMS generally maintains a minimum reserve of about 15%.

(*c*) A Transmission Planning Task Force has been established by the Engineering Committee which conducts load flow and stability studies for WUMS. The studies encompass both immediate future and far future system expansion plans. Stability studies include both routine analysis of simple faults and investigation of disaster situations. The joint studies of generation and transmission facilities required for serving future loads have resulted in deferred installation of generating capacity. The participants also have coordinated transmission line construction so as to avoid duplication of facilities and to minimize transmission facilities on each system.

(*d*) A Transmission Design Task Force has been established to promote uniformity of design, interchangeability of materials and equipment, and joint efforts in the procurement of right of way.

(*e*) A Relay Task Force has been established to coordinate system and tie line relay settings.

7. Operating Practices:

(*a*) Participants buy and sell various types of capacity and energy which are identified as reserved power, short term power, emergency energy, economy energy, and maintenance energy.

(*b*) See Item 6B for installed reserve coordination comments.

Spinning reserves are coordinated by the Operating Committee on an hourly basis. The companies share the spinning reserve requirements for the largest unit in operation at the time.

(*c*) Maintenance is coordinated by the Operating Committee in order to achieve the smallest amount of capacity out for maintenance at any one time consistent with the seasonal demands for power. An exchange of maintenance energy also occurs between members of WUMS and companies external to that group.

(*d*) Each participant maintains its own system operating center and has tie line load control equipment. Five of the six participants have need for automatic economic dispatch equipment and have installed it. Operating centers for each company are directly connected with the operating centers of all the other companies through direct telephone communications. Telemetering of tie lines and other essential operating information is universally employed.

Miscellaneous

ESE does not belong to an organized coordinating group as such, but does have operating agreements with Consumers Power Company, UPP, U.S. Hydro Plant at Sault Ste. Marie, and Cloverland Electric Coop. System studies and relay settings are coordinated with Consumers Power system and they are currently working with Consumers Power Company on a plan to coordinate spinning reserve.

Illinois-Missouri Pool

1. Type of Organization:

The Illinois-Missouri Pool was formed under an agreement between Central Illinois Public Service Company, Illinois Power Company and Union Electric Company, dated August 15, 1952. It is a coordinated planning and operating pool with each participant accepting responsibility for coordination of planning and installation of generation and transmission facilities and coordination of the operation of its system with those of the other participants. It should be noted that the Illinois-Missouri Pool is not in itself an entity. The name 'Illinois-Missouri Pool' was suggested as a reasonably descriptive and short name for the Pool, which was formed as a result of the first mentioned agreement and was adopted by the Operating Committee.

2. History of Development:

In the late 40's and early 50's, considerable strides were being made in the development of larger generating units. Labor and other costs were increasing, and it was rather obvious that it would be necessary for utilities to find ways of utilizing these larger and more efficient units with their attendant economies. Offsetting these economies for an isolated system was the fact that the installation of larger units would require larger generating reserves. These facts naturally led to the formation of the Illinois-Missouri Pool which made it possible for the participants to obtain the benefits available from larger units and to share in the increased reserves necessary.

While these factors alone would undoubtedly have prompted the formation of the pool, the Atomic Energy Commission's decision to locate a plant near Paducah, Kentucky, generated additional pressure to form the pool in 1952. The present three Illinois-Missouri Pool participants, together with Kentucky Utilities and Middle South Utilities, helped to form Electric Energy, Inc. Electric Energy, Inc. proceeded with the installation of a one million kw generating station at Joppa, Illinois, to supply power to the Atomic Energy Commission.

The northern sponsors of Electric Energy, Inc,; namely, the Illinois-Missouri Pool participants, agreed to interconnect their respective systems with a 230 kv transmission line to Electric Energy, Inc. This line, in addition to supplying interim start-up power for the Atomic Energy Commission plant, was also used to supply backup power to Electric Energy, Inc., as well as surplus power from Electric Energy, Inc. to the northern sponsors.

An interconnection agreement was entered into on August 15, 1952, and subsequently modified with a new agreement on November 8, 1956, with amendments on January 16, 1963, December 4, 1964, and June 4, 1965.

3. List of members:

	1967 peak load (MW)	*Jan. 1, 1968 capability (MW)*
Central Illinois Public Service Co	868	1, 178
Illinois Power Co	1, 338	1, 444
Union Electric Co	3, 212	3, 053
Ill-Mo Pool TOTAL [1]	5, 418	5, 675
Central Illinois Light Co.[2]	474	545

[1] The Illinois-Missouri Pool participants are also entitled to 612 mw of Electric Energy, Inc., surplus capacity during peak load periods and slightly more during off-peak periods.

[2] Central Illinois Light Company, although not a participant in the Pool, has agreements with Illinois Power Company which provide for coordinated planning and operation.

4. Requirements for Participation:

Since the Illinois-Missouri Pool is a name adopted for and applied to the participants in a certain interconnection agreement, it is not a membership-type of organization, even though the participants are oftentimes referred to informally as "members". Inasmuch as the participants are the corporate entities signatory to the interconnection agreement, any extension of the interconnection agreement to provide for additional participants would necessitate the execution of a whole new agreement and would require the consent of all participants involved.

5. Organization Structure Including Official Positions, Any Committees and their Functions, and Methods of Arriving at Decisions Affecting Members of the Coordinating Groups:

The agreement provides for the appointment by each participant of a member and an alternate member of an operating committee. This committee has authority to establish operating and maintenance schedules, control and operating procedures and principles of interchange accounting and such other duties and authority as is provided by the agreement or may be conferred upon it by mutual agreement of all the participants. In general, matters coming under the jurisdiction of the operating committee must have the unanimous agreement of all members of the committee. In the event that the committee is unable to agree on any matter coming under its jurisdiction, that matter is referred to the chief executive of each of the participants and some kind of settlement is negotiated. In the unlikely event that a negotiated settlement is impossible, each participant has the right to avail itself of a three-year cancellation provision.

6. Practices in the Planning and Development of Facilities Including:

(*a*) Coordinated Load Projections:

Each participant projects its own load and these individual projections are combined into a pool load projection.

(*b*) Coordinated Planning for Reserves:

By agreement, each participant shares in the pool reserve in the ratio of its accredited demand to the Pool's accredited demand.

(*c*) Coordinated System Stability Studies:

The system planning groups of the participants participate in joint planning and stability studies.

(*d*) Joint or Staggered Participation in Facilities Development:

Joint participation in facilities development by participants is a common occurrence. Each facility is handled on a negotiated basis and separate facility use agreements provide for facility rental charges between participants.

7. Operating Practices, Including:

(*a*) Exchanges of Capacity and Energy:

Operating practices are coordinated by the operating committee. Each participant is entitled to its share of whatever capacity is available in the pool. Any difference between the installed capacity of a given participant and that participant's capacity responsibility is settled for by capacity equalization payments of $1.25 per kw per month.

Various types of energy, such as deficiency, equalization, emergency, economy and excess, are exchanged regularly.

(*b*) Coordination of Reserves Including Spinning Reserves:

The Illinois-Missouri Pool's practice is to provide for spinning reserve at all times in an amount equal to or greater than the largest unit operating in the pool. Since this must cover the peak load period, it obviously provides spinning reserve well in excess of the requirements at other times. By agreement this spinning reserve is distributed among the participants in proportion to their respective accredited demands. Up to 50% of the pool's spinning reserve requirement may be in neighboring systems on a reciprocal spinning reserve basis.

Central Illinois Light and Illinois Power have a reciprocal spinning reserve agreement for 20 mw.

(*c*) Coordination of Maintenance:

Maintenance schedules are coordinated by the operating committee on a continuous basis.

(*d*) Economic Dispatch Including Descriptions of Control Facilities:

Central Illinois Light and each participant in the Pool has its own automatic load control and economic dispatch equipment. Central Illinois Light, Central Illinois Public Service, and Union Electric Company all have equipment which performs the economic dispatch function automatically. Illinois Power precalculates its economic dispatch schedule and makes manual adjustments of the load control equipment from time to time.

Iowa Pool

1. Type of Organization:

The Iowa Pool is provided for by an agreement among six electric utilities, operating wholly or partially in Iowa. The agreement provides for coordinated planning and operation and contains various Service Schedules for capacity and energy transactions between the members.

2. History of Development:

The Iowa Pool contract became effective January 1, 1969 as an agreement among six electric utilities. The contract was patterned after the Upper Mississippi Valley Power Pool Agreement which has been in operation for several years. The Iowa Pool Interconnection and Coordination Agreement had a predecessor in the Iowa Pool Interconnection Agreement which was in use from July 1, 1958 to January 1, 1969.

3. List of Members:

	1967 peak load (MW)	*Jan. 1, 1968 capability (MW)*
Corn Belt Power Cooperative	100	116
Iowa Electric Light and Power Company	472	436
Iowa-Illinois Gas and Electric Company	452	415
Iowa Power and Light Company	497	633
Iowa Public Service Company	312	421
Iowa Southern Utilities Company	175	92
Total	2, 008	2, 113

4. Requirements for Participation:

The Pool Agreement contains no specific requirements for membership. The preamble paragraphs establish that the parties are engaged in the business of generating and transmitting electric energy, their operating areas closely adjoin each other with their systems already interconnected or capable of being interconnected, and they recognize the benefits of coordinating the installation and operation of generating and transmission facilities.

5. Organizational Structure:

The Iowa Pool is administered by an Administrative Committee of six members with one member appointed by each of the six Pool members. Each member may also appoint an alternate to act in the absence of the regular members. The committee has a chairman normally rotated among the six companies at one-year intervals. The Chairman may appoint such other officers as are deemed necessary. A list of responsibilities as described in the Interconnection Agreement is as follows:

(*a*) Prescribe the manner of reflecting terminations of power sales and purchases in a party's accredited system demand.

(*b*) Establish conditions and procedures for determining net generating capability.

(*c*) Determine and assign the accredited capability and annual accredited system demand for each party in accordance with the provisions of the agreement.

(*d*) Determine whether quick-start generating units may be included as spinning reserve.

(*e*) Establish a method of determining the most direct route for the transmission of power and energy.

(*f*) Record the minutes of all committee meetings and furnish copies to each member.

(*g*) Determine and recommend such practices, rules and procedures as may be required to coordinate the plans for additional generating and transmission facilities.

(*h*) Schedule meetings at least twice annually.

(*i*) Obtain semi-annually from each party a monthly load and capability forecast for such party's system for a period of four years or more.

(*j*) Review demand and capability forecasts and reserve capability obligations of the parties periodically and collect data and information as is deemed necessary.

(*k*) Make coordinating studies of the plans of the parties for the construction of generating and transmission facilities and purchases and sales between parties and recommend a plan to the Executive Officer of the systems.

(*l*) Determine practices, rules, and procedures required to coordinate the operations of the systems.

(*m*) Periodically review the spinning reserve obligation of the parties.

(*n*) Make studies pertinent to the interconnected operation of the systems and conduct transmission network studies.

(*o*) Coordinate the maintenance schedules of the parties.

(*p*) Determine and recommend the procedures for supplying the spinning reserves of the pool in the event of a large generator failure or other comparable contingency.

(*q*) Establish other committees as deemed necessary.

(*r*) Change the reserve capacity obligation if conditions warrant it.

(*s*) Determine the source and amount of equalization power to be purchased by a deficient party.

(*t*) Determine and recommend how spinning reserve shall be restored after the occurrence of an emergency.

(*u*) Establish the spinning reserve obligation of the parties and coordinate the spinning reserve of the pool.

(*v*) Establish principles and practices to balance out in kind the difference between net scheduled deliveries and actual net deliveries.

(*w*) Determine what records and metering data are necessary to develop a clear history of transactions between parties.

(*x*) May adjust the billing periods.

(*y*) Determine principles and practices for the delivery of emergency energy.

(*z*) Develop formulae to determine compensation for losses.

Any action, determination, or recommendation requires a two-thirds affirmative vote by the Administrative Committee. Such action, determination, or recommendation becomes binding after thirty days unless objection is made thereto by the Executive Officer of any party. If the Executive Officers do not unanimously approve or disapprove the decision within sixty days after the Administrative Committee vote, any party may invoke the arbitration provisions of the agreement to ultimately solve the problem.

The arbitration provision cannot be used nor does the Administrative Committee or a Committee of the Executive Officers have authority to require a Party to install facilities, restrict a Party's scheduling of maintenance, restrict a party's election whether to install facilities or purchase power to maintain its accredited capability, or amend or supplement the agreement.

6. Coordinated Load Projections:

Each Pool member prepares a long range estimate of his maximum summer and winter load and a four-year estimate of his twelve monthly expected peak loads. Both of these estimates are based on the principle of forecasting maximum probable loads. The long-range estimate is used for coordinated planning of production and transmission facilities and the short-range estimate for preparation of coordinated maintenance schedules and for determining the purchases and sales to be made.

Coordinated Planning for Reserves:

A study was made several years ago to develop the reserve required to eliminate the probability of a forced outage requiring load reduction at intervals more frequent than seven years. During this study, it was actually found that the maximum risk only occurs during selected days

356-240 O—70——16

in three months of each year and that this three months of maximum risk period does not change after maintenance is added to the other nine months. One therefore concludes that the exposure of one forced outage in seven years, as determined by the computer, is actually equivalent to one in twenty-eight years in actual experience.

From this study it was determined that 15 percent in reserve generating capacity was enough to all but eliminate the risk of a forced outage developing a service interruption.

Later studies made in connection with the 345 kv transmission line connecting the Upper Mississippi Valley Pool, the Iowa Pool, and the Illinois-Missouri Pool, developed a 3 percent reduction in reserve capacity requirement due to the improved forced outage diversity. The Iowa Pool therefore has dropped its reserve capacity requirement from 15 percent to 12 percent in 1967 when the 345 kv Twin Cities-Iowa-St Louis line went into service.

Coordinated System Studies:

Digital computer load flow studies of the Iowa Pool and adjoining systems are conducted to test the adequacy of the existing system and of proposed system additions for normal and emergency conditions. The Iowa Pool cooperates with regional organizations, such as MAPP and MAIN, in computer studies examining the limitations and the reliability of the regional transmission system.

The Iowa Pool also performs digital computer fault studies and coordinated studies of the transmission protective system.

The system stability study was performed in connection with the Twin Cities-Iowa-St Louis 345 kv transmission line. The Iowa Pool cooperates with MAPP in regional stability studies as related to the security of the protective relaying system for major system disturbances. Stability studies related to the installation of new generating units are conducted by individual parties associated with the installation when such studies are deemed necessary or desirable.

Joint or Staggered Participation in Facilities Development and Capacity Purchased:

The six-year capacity requirements, 1969 through 1974, for the six systems in the Iowa Pool will be covered by the following jointly planned new facilities and purchases:

1969:

32 mw	Iowa Public Service Company, Gas Turbines.
393 mw	Summer Purchases and 300 mw Winter Purchases from outside the Iowa Pool

1970:

375 mw	Iowa-Illinois Gas and Electric Company, Quad Cities, Nuclear Station.
614 mw	Summer Purchases and 128 mw Winter Purchases from outside the Iowa Pool.

1971:

355 mw	Summer Purchases and 169 mw Winter Purchases from outside the Iowa Pool.

1972:

325 mw	Iowa Public Service Company, Neal Unit #2.
400 mw	Iowa Power and Light Company, Cooper Nuclear Station, Long-Term Participation Purchase.
272 mw	Summer Purchases and 234 mw Winter Purchases from outside the Iowa Pool.

1973:

149 mw	Summer Purchases and 111 mw Winter Purchases from outside the Iowa Pool.

1974:

550 mw	Iowa Electric Light & Power Company, Duane Arnold, Nuclear Energy Center.
24 mw	Summer Purchases and 36 mw Winter Purchases from outside the Iowa Pool.

7. Exchanges of Capacity and Energy:

The Iowa Pool arranges for the installation and purchase of sufficient capacity to carry the Pool load plus 12 percent reserve. The arrangements for the capacity sometimes develops an unequal distribution among the six systems. Purchases and sales are made between the systems under one of the various service schedules so that each system can meet its responsibility.

Coordination of Reserve, including Spinning Reserves:

A minimum spinning reserve of 100 mw is scheduled and during most hours of the day the reserve exceeds 100 mw by a wide margin. In addition, the Pool has arranged with seven neighbors to provide a total of 150 mw of additional spinning reserve. In exchange for this reserve, the Iowa Pool has offered an amount varying between 5 and 75 mw to each of these neighbors during an emergency period in their system. These seven arrangements provide for the emergency service if an emergency is not occurring in the system of the supplier.

The 100 mw of spinning reserve is assigned among the Pool members in proportion to their maximum annual demands and the ratio of each largest unit to the sum of all participants' largest units. Each member distributes his assignment among the generating units he has in service. The amount of spinning reserve assigned to each generating unit must not exceed one-sixth of the capacity of that unit and the unit must be synchronized to the bus and under governor action. This insures that the entire 100 mw will be supplied automatically if the system frequency drops to 59.5 Hz or lower.

Additional capacity is normally available from fast start units, such as gas turbines or diesels.

Coordination of Maintenance:

Maintenance is coordinated by the Pool Operating Committee and load dispatchers so that the Pool has sufficient capacity to carry its load, the transmission lines have sufficient reserve to cover capacity and emergency transfers, and reserve capacity is adequate and adequately distributed throughout the interconnected system of the six Pool companies.

Economic Dispatch, including Description of Control Facilities:

At 2:00 p.m. each day, each system dispatcher puts his offers of tomorrow's economy energy on the teletype. These offers are accepted, with the highest priced decrements and the lowest priced increments having first priority. Most of the dispatchers use automatic controls for dispatching within their systems. These controls will usually read out the incremental cost of the next kilowatt of capacity. The intersystem economy dispatching is not carried on automatically but by dispatchers' transactions as described above.

Mid-America Interpool Network

The power systems in the Middle West have long recognized the need for coordinated planning and operation of their power systems. Numerous interconnections at 138 kv have been in service for as long as forty years and in recent years interconnections at 345 kv have been growing at a rapid rate. Recently a 765 kv interconnecting line was authorized. Several formal pools have been created in the Middle West to facilitate coordination.

About five years ago, a group of planning engineers representing the major companies and pools in the Middle West started to hold regular meetings in order to broaden the degree of coordination. At these meetings, system problems of mutual interest were discussed, principally the coordination of generation and transmission projects. These meetings brought gratifying results and in November 1964, it was decided to formalize this organization by creating MAIN, the Mid-America Interpool Network.

In June 1967, the MAIN Agreement was revised to coordinate its membership and its activities with other developments in the area. The companies in the MAIN organization were grouped into regular members and liaison members as follows:

	1967 peak load (MW)	Jan. 1, 1968 capability (MW)
Regular Members:		
Commonwealth Edison Company	7, 643	8, 547
Illinois Group:		
Central Illinois Light Co	474	545
Central Illinois Public Service Co	868	1, 178
Illinois Power Co	1, 338	1, 444
Missouri Group:		
Union Electric Co	3, 212	3, 053
Associated Electric Coop	427	322
Eastern MAPP Group:		
Interstate Power Co	329	564
Iowa Electric Light & Power Co	472	436
Iowa-Illinois Gas & Electric Co	452	415
Iowa Power & Light Co	497	633
Iowa Public Service Co	312	421
Iowa Southern Utilities	175	92
Northern States Power Co	2, 323	2, 232
Wisconsin-Upper Michigan Systems:		
Wisconsin Electric Power Co	1, 924	2, 422
Madison Gas & Electric Co	188	211
Wisconsin Michigan Power Co	[1] 401	[1] 105
Wisconsin Power & Light Co	620	658
Wisconsin Public Service Corp	539	653
Upper Pensinsula Power Co	95	125

Liaison Members:
American Electric Power Company Group.
Indiana Group:
Indianapolis Power & Light Co.
Public Service Company of Indiana, Inc.
Northern Indiana Public Service Co.

[1] Included in WEPCo totals.

As seen from the above, MAIN is an association of power companies and groups of companies, some of which may already be members of power pools. In addition, each of the systems or groups in MAIN may represent other companies in their respective geographical areas. This allows relatively small companies to participate in the development and execution of MAIN plans and programs and to receive the benefits of coordinated long-range planning.

The regular members of MAIN have a generating capacity in 1968 of about 30,000,000 kw and serve major portions of Illinois, Missouri, Iowa, Minnesota, and Wisconsin. The systems comprising MAIN are interconnected by a 345 kv regional transmission grid; also, there are interconnections with neighboring systems and pools outside of MAIN with heavy connections to the east, principally to the American Electric Power system.

The purpose of MAIN, as stated in the Agreement, is "to promote maximum coordination of planning, construction and utilization of generation and transmission facilities on a regional basis by MAIN members individually and as members of the power pools to which they belong, in order to improve the reliability of electric bulk power supply in the areas served by such members and pools."

While the Agreement deals primarily with reliability, it also makes reference to economics. It states that "It is expected, however, that groups of MAIN members will develop planning and operating arrangements to achieve increasing economies in bulk power supply, such as:

A. Joint scheduling of capacity, arrangements for economic dispatch of generation, and coordinated use of transmission facilities.
B. Making maximum use of the generating capacity that is available because of seasonal diversity characteristics.

C. Interchange of energy for economy reasons."

Officers of MAIN consist of a chairman and vice-chairman. There are three permanent committees; the Executive, Engineering and Operating Committees.

The Executive Committee consists of a representative of each group of companies designated on the membership list.

The Engineering Committee is the planning arm of MAIN and undertakes such activities as will contribute to improving the high degree of electric service reliability through more complete coordination of the long-range plans of the members of MAIN.

The Operating Committee is the operating arm of MAIN. It undertakes such activities as will aid in coordinating the operating activities of the members of MAIN to maintain reliable electric service.

The Engineering Committee meets at regular intervals to carry on its coordination activities. At these meetings, information on the capacity programs of the various companies are interchanged and discussed. Reports are received from various task forces that carry on the detailed activities. The principal group is the Transmission Task Force which works continually analyzing load flow and stability problems as a check on the adequacy of the transmission system. Computer analyses are made of the interconnection capabilities between the various systems in MAIN, studies are made of maximum credible incidents, and operating guides and critical facilities lists are developed. The maximum credible incidents studies test the stability of the interconnected system to withstand the loss of an entire generating station or large substation.

Operating guides and critical facilities lists provide useful information to the operating personnel to improve the reliability of operation on the bulk power system. Following are lists of completed and current studies of the Task Force:

Completed Studies:

1. 1966 Extreme Disturbances.
2. 1968 Interconnection Capabilities.
3. 1966 Summer Critical Facilities List.
4. 1966–67 Winter Critical Facilities List.
5. 1967 Interconnection Capabilities.
6. 1967 Summer Critical Facilities List.
7. 1967–68 Winter Critical Facilities List.
8. 1970 Interconnection Capabilities.
9. 1968 Extreme Disturbances.
10. 1968 Summer Critical Facilities List.
11. 1968 Operating Study.
12. 1968–69 Winter Critical Facilities List.

Current Studies:

1. 1969 Operating Study.
2. 1970 Extreme Disturbances.
3. 1973 Extreme Disturbances.
4. 1973 Interconnection Capabilities.
5. 1976 Interconnection Capabilities.

Another task force has been developing a coordinated future program for the MAIN systems. Studies are in progress to establish a 1980 system; computer studies are being made to check the coordination of the various plans submitted by the individual systems. As a result of this effort, we expect to produce a coordinated plan of development for the MAIN area.

Other task forces of the Engineering Committee have made studies of load diversities in the area and factors affecting the required generator reserves.

The Operating Committee of MAIN was established in 1967. Previous to this time, the Engineering Committee had carried on various activities affecting the operating reliability. One of the results of this effort was the establishment of the MAIN Coordination Center in Chicago in April 1967. This Center has the function of coordinating the day-to-day operations of the MAIN companies and to maintain

liaison with neighboring systems; through its operations, there is assurance that the generating capacity in the region will be fully utilized. Also, the Center acts to prevent unsafe operating situations on the regional transmission system.

Another operating activity carried on by the Engineering Committee was the establishment of an operating guide covering the action to be taken by the MAIN companies in the event that a shortage of generating capacity should develop in the region. This includes a program of load shedding to arrest a decline in system frequency.

The planning coordination carried on by the Engineering Committee has led to a number of achievements. Following are examples.

1. The American Electric Power system has a winter peak while the companies in Illinois have a summer peak. This has resulted in contracts for seasonal diversity exchange between AEP and the Illinois-Missouri Pool amounting to 200 mw, and also between AEP and Edison for 100 mw. Starting in 1970, the diversity exchange between AEP and Edison will be 200 mw.
2. Coordination of the generating programs of the various companies in MAIN has resulted in a number of cases where generating units have been delayed by coordinating the programs of contiguous companies. Following are specific examples:
   (*a*) Northern Indiana Public Service Company deferred a 396 mw unit (Bailly #8) from December 1967 to June 1968 by purchases from American Electric Power and Commonwealth Edison companies.
   (*b*) Northern States Power Company deferred a 550 mw unit (A. S. King #1) for two years, from 1966 to 1968, by purchasing from companies connected to the 345 kv system.
   (*c*) Wisconsin Electric Power Company deferred a 300 mw unit (Oak Creek #7) from December 1964 to June 1965 by purchasing from Commonwealth Edison Company.
3. The Indiana Pool found it possible to install a larger unit (450 mw) in 1969 than would otherwise be economically possible by selling some surplus capacity to AEP. This transaction will allow the Indiana Pool to benefit from economies of scale inherent in the installation of larger units.
4. Recently Commonwealth Edison joined with Iowa-Illinois Gas and Electric in the construction of a new generating station (Quad-Cities) on the Mississippi River, near Moline, Illinois. Two 800 mw nuclear units are being installed in this station for service in 1970 and 1971. Iowa-Illinois will own 25% of this capacity.
5. In the field of transmission, several joint 345 kv projects have been carried out by the MAIN companies as a means of coordinating the generating programs and providing for adequate reserves between systems.
   (*a*) Minneapolis-Milwaukee-Chicago, 1966.
   (*b*) Minneapolis-Iowa-St. Louis, 1967.
   (*c*) Chicago to St. Louis, 1968.
   (*d*) Breed to Coffeen, 1968.
   (*e*) St. Louis to Kansas City, 1968.
   (*f*) Kansas City to Omaha, 1969.
   (*g*) Minneapolis to Omaha, 1970.
   (*h*) Iowa to Chicago, 1970.
   (*i*) Michigan to Indiana and Ohio, 1969.
   (*j*) Hills to Des Moines, 1969.
   (*k*) Des Moines to Omaha, 1970.
6. Commonwealth Edison and American Electric Power are proceeding with an extension of the 765 kv transmission system from the Lakeville Substation of AEP to a new substation in CECo territory. In conjunction with this joint transmission project, CECo will purchase 500 mw from AEP for the summer period starting in 1974 for a period of four years.
7. CECo has initiated discussions with the Consumers Power Company on the possibility of CECo participating in the pumped storage generating station to be built near Ludington, Michigan, by the Consumers Power Company. This station is scheduled for service in 1973–1974.

The MAIN Operating Committee, since its formation in the summer of 1967, has been meeting at regular intervals. At these meetings, they have discussed a number of subjects and will continue to coordinate the activities of the various companies on these items:

1. MAIN Coordination Center:

   The Committee will follow the activities of this Center and make recommendations for its operation.

2. Load Shedding:

   They have reviewed and coordinated the load shedding programs in various MAIN companies.

3. Communications:

   A report has been prepared on regional communications. The objective is to develop voice communication and teletype systems between the various load dispatching offices of the MAIN companies to assure adequate communications for emergency conditions. These systems also are tied in with the neighboring systems outside the MAIN group.

4. Operating Terminology and Definitions:

   To assure uniform action under various conditions, the Committee is discussing various definitions, such as "emergency energy interchange."

5. Gas Turbines:

   Many companies in MAIN are installing gas turbines for peaking purposes. The proper use of these gas turbines is being discussed.

6. Spare Parts and Material:

   Availability of spare parts for 345 kv equipment is being interchanged between companies.

7. Power Disturbance Investigations:

   The Operating Committee will make investigations of all operating disturbances in the regions that affect a number of systems.

8. Maintenance:

   Information is being interchanged on turbo-generator maintenance to provide necessary coordination of this important function.

Mid-Continent Area Power Planners

The Mid-Continent Area Power Planners (MAPP) is an organization of midwest electric utilities that was formed by 22 generation and transmission systems in February 1963 to promote coordinated planning among its members with a view toward establishing a large regional power pool. The current number of members is 54 and includes 15 investor-owned utilities, 8 G&T cooperatives, 2 public power districts, the Manitoba Hydro-Electric Board of Canada, and 28 municipal electric utilities. A membership list is appended as Attachment #1. Membership in MAPP is open to all local electric utilities that can contribute to and benefit from its coordination program. All of the members of the Iowa Pool and Upper Mississippi Valley Power Pool are members of MAPP. The service area of MAPP members includes all or part of ten Midwestern states from Montana to Wisconsin and from Missouri to the Canadian border, plus the province of Manitoba. MAPP members serve more than 3½ million customers with a total 1968 estimated peak load of 12,500 mw.

The MAPP program and policies are directed by a Management Committee composed of one representative from each member utility except that municipal utilities have one representative from each state. Administration of the program is handled by an eight-member executive committee. The membership consists of eight members elected from the Management Committee and include four representatives from investor-owned utilities, three from generation and transmission cooperatives, and one representative from a public power district. The chairman of the Management Committee is also chairman of the Executive Committee.

Planning for coordinated development of generation and high voltage transmission facilities is carried out by a Planning Committee. Each major system or power pool within the MAPP membership is represented in this committee. The primary function of the Planning Committee is to develop broad plans for expansion of generation and high capacity interconnections to improve cost and reliability of electric service. Detailed planning of specific facilities is handled by individual systems or sub-regional groups that will build and operate them. Studies which have been or are being run also include generation reserve requirements based on probability of loss of capacity, savings available with optimal operation of generation, and reliability studies.

An extensive grid of 230 kv and 345 kv line has been planned under the MAPP program in close collaboration with MAIN member utilities to the east and MoKan member utilities to the southwest of the MAPP area. This transmission grid is described in the section on Patterns of Generation and Transmission. Construction of this transmission grid will be virtually completed by 1970–72 at a cost of over $250 million.

The basic objective of the MAPP organization was to promote integrated regional planning among its members to improve the quality and cost of service to the consumer. However, MAPP recognized that with the installation of the multiple-owned EHV grid, large generating units and increased intersystem dependency on large power exchanges, a central agency would be required to coordinate day-to-day operations of the entire network. The MAPP Management Committee authorized the establishment of a Coordination Center in late 1966 to coordinate operations of bulk power supply in the MAPP area. A MAPP staff, consisting of four engineers, a coordinator, two dispatchers, and a secretary, has been employed with offices in Minneapolis, Minnesota. The Coordination Center works under the direction of a 26 man Coordinating Committee. This committee is made up of 26 representatives actively engaged in the system operation field from each of the 25 power suppliers of MAPP who are members of the Coordination Center and one representative from the Bureau of Reclamation who participates in the support of the Coordination Center. Coordination of operation with the municipals is presently effected through the MAPP power supply representative of the system to which the municipal is connected.

The Center began an eight hour day, five day a week operation on June 1, 1967. The Center is enhancing system security by providing the necessary overview of the overall regional operations which includes coordinating transmission and generation maintenance outages, power exchanges, spinning reserve and monitoring the loading of critical power facilities. The Coordinating Committee and the MAPP staff have prepared various operating procedures and surveys to cover both normal and emergency operation of the MAPP bulk transmission network. An automatic under-frequency load shedding plan has been coordinated among all of the member systems. The MAPP members have installed or are installing underfrequency relaying to start shedding load at predetermined frequency levels with a total load of 30 to 35 per cent shed.

The basic communication link with the dispatchers to the Coordination Center is through teletype. The MAPP office has three teletype machines which connect it to the dispatch centers of the Iowa Pool, Upper Mississippi Valley Power Pool, and the MAIN organization. The MAPP Coordinating Committee recently approved the installation of 100 wpm teletype system for all members of the Coordination Center and St. Joseph Light and Power and Kansas City Power and Light. This system which will be installed in the spring of 1969, will replace the present Upper Mississippi Valley Power Pool and Iowa Pool teletypes.

The Coordinating Committee has four working subcommittees: Relaying, Computer Operational Study, Operating Procedures and Center Development. The Center Development Subcommittee is formulating a detailed proposal for expanded centralized dispatching facilities to keep pace with future needs.

A Mid-Continent Area Reliability Coordination Agreement has been executed on May 1, 1968, which provides for review of each system's plans and operating practices as they affect reliability of area bulk power supply. This agreement provides for a council made up of a representative from each of the members. This council has established a design review committee and an operating review committee. The design review committee with the assistance of the MAPP staff will review and evaluate each member's plans for generation and transmission facilities relevant to reliability of the bulk power supply and

perform studies and investigations concerning the overall adequacy of future transmission and generation reserves in the Mid-Continent Area. This committee will make recommendations to the council as to the adequacy of these plans with respect to system criteria established by the council. The operating committee will likewise review and make studies concerning the operation of the overall bulk supply as it affects reliability and make recommendations to the council concerning adequacy as judged by the operating standards established by the council.

The direction of a seven year program for development of the MAPP Coordination Center has been approved in principle by the membership. The development is designed for three phases:

Phase I. consists of the period from now until 1972. Additional people would be employed as dispatchers so that in 1970 a full twenty-four hour, seven day operation would be in effect. Also, during this period a limited amount of metering would be installed in order that an approximate picture could be obtained at any instant of the power flows on the entire MAPP network.

Phase II. considers the installation of a medium size computer in 1972 to perform system security checks, monitoring and predicting of first and second contingency operations.

Phase III. consists of installing a second medium size computer or two small scale computers by 1975 which would be able to perform economic dispatch with backup provided by the first computer.

MAPP Membership List

	1967 peak load (MW)	Jan. 1, 1968 capability (MW)
1 Canadian Crown Corporation:		
Manitoba Hydro-Electric Board	1, 102	1, 416
15 Investor-Owned Electric Utility Companies:		
Black Hills Power & Light Co	94	110
Interstate Power Co	329	564
Iowa Electric Light & Power Co	472	436
Iowa-Illinois Gas & Electric Co	452	415
Iowa Power & Light Co	497	633
Iowa Public Service Co	312	421
Iowa Southern Utilities Co	175	92
Lake Superior District Power Co	91	108
Minnesota Power & Light Co	482	511
Montana-Dakota Utilities Co	157	207
Northern States Power Co	2, 323	2, 232
Northwestern Public Service Co	98	73
Northwestern Wisconsin Electric Co	7	7
Otter Tail Power Co	192	280
Union Electric Co	3, 212	3, 053
Investor-Owned subtotal	8, 893	9, 142
28 Municipal Electric Utilities:		
Adrian, Minnesota	1. 1	1. 5
Alexandria, Minnesota	8. 2	14. 5
Ames, Iowa	25. 4	29. 2
Austin, Minnesota	27. 0	35. 2
Cedar Falls, Iowa	22. 6	35. 3
Delano, Minnesota	2. 4	2. 6
Detroit Lakes, Minnesota	7. 2	6. 0
Fairfax, Minnesota	1. 1	2. 0
Fairmont, Minnesota	15. 0	25. 0
Glencoe, Minnesota	7. 0	9. 8
Hibbing, Minnesota	14. 2	16. 4
Hutchinson, Minnesota	10. 9	13. 3

	1967 peak load (MW)	Jan. 1, 1968 capability (MW)
28 Municipal Electric Utilities—Continued		
Kenyon, Minnesota	1.3	1.9
Lake Crystal, Minnesota	1.1	2.3
Lincoln, Nebraska	185.0	9.0
Madelia, Minnesota	2.8	5.6
Marshall, Minnesota	9.1	7.0
Melrose, Minnesota	3.8	2.9
Moorhead, Minnesota	23.0	24.0
Muscatine, Iowa	42.8	55.3
New Ulm, Minnesota	17.1	27.9
Owatonna, Minnesota	14.6	18.0
Redwood Falls, Minnesota	4.0	3.5
Sleepy Eye, Minnesota	3.1	6.2
Virginia, Minnesota	11.8	16.9
Watertown, South Dakota	12.0	8.0
Windom, Minnesota	4.1	3.5
Worthington, Minnesota	13.9	16.5
Total	491.6	399.3
2 Public Power Districts:		
Consumers Public Power District	400	120
Omaha Public Power District	654	627
Public subtotal	1,054	747
8 Rural Electric G & T Cooperatives:		
Central Iowa Power Cooperative	126	124
Cooperative Power Association	196	11
Corn Belt Power Cooperative	100	116
Dairyland Power Cooperative	283	305
Eastern Iowa Light & Power Coop	34	65
Minnkota Power Cooperative, Inc	123	45
Northern Minn Power Association	58	83
Rural Cooperative Power Assoc	99	150
Rural subtotal	1,019	899

Missouri Basin Systems Group

The Missouri Basin Systems Group was formally organized in January 1963. It is an operating power pool with a planning committee and operating committee, established under the Missouri Basin Pooling Agreement of which all members of MBSG are signatories. The Pooling Agreement established formal mechanisms for joint planning, and a Joint Transmission System to be added to and used by all Participating Systems as these are defined in the Pooling Agreement.

The MBSG is composed of a large number of municipal electric systems, rural electric cooperatives and public power districts in eight states of the Missouri Basin, and the U.S. Bureau of Reclamation. A list of the members is attached to this memorandum.

The Systems Group was organized to achieve joint, coordinated planning for the provision of the power generating and transmission facilities in a huge geographic region that are required to meet the steadily growing power needs of the members of the Group. To date, the primary source of power supply

for most members of the Systems Group has been the Bureau of Reclamation but their requirements are outrunning the Bureau's supply of hydro power. Accordingly, it has been and will be increasingly necessary to add thermal generation to supplement the hydro available to the members of the Systems Group. The second principal purpose of the Systems Group is to provide for the coordinated operation on a pooled basis of the Federal hydro and thermal generation added to the Joint System.

Requirements for Participation

The members of the Systems Group consist of the U.S. Bureau of Reclamation and the rural electric cooperatives, municipal electric systems, public power districts and other agencies which, under Federal law, have first priority on the power offered for sale by the Department of Interior (Bureau of Reclamation). There has been discussion within the Planning Committee of the desirability of amending the terms under which the Systems Group is organized so that other interested electric utilities can become members of the Systems Group. At the present time, such utilities are welcome to participate in the Planning Committee discussions if they wish to do so and to take part in all joint planning and other activities. Further, it appears that, if such other utility or utilities were to indicate positive interest in formal membership in the Systems Group, steps could be taken to make this possible.

Organizational Structure

The Systems Group has a chairman, vice-chairman, secretary and treasurer. These officers are elected annually, at the regular annual membership meeting of the Missouri Basin Systems Group. There are two major committees; the Planning Committee and the Operating Committee. The Systems Group has a full-time Executive Director and Staff Counsel, headquartered in Denver, Colorado.

The Planning Committee consists of one representative designated by the Federal Government; a representative of each generation and transmission cooperative or similar organization; and one representative elected for each state jointly by all other Participating Systems in that state (including municipal systems) which are not otherwise represented.

The general responsibilities of the Planning Committee are as follows:

A. Investigate and make engineering studies concerning the location, size, time of installation, and/or engineering of thermal generating facilities, and make studies regarding the possible adjustments to the account of the Joint Transmission System for such locations of additional thermal units that may increase or decrease transmission costs, for the purpose of coordinating such installations for the maximum benefit of all the Participating Systems;

B. Develop a coordinated area transmission plan and prepare and submit annually a study of the adequacy of the Joint Transmission System to carry the power requirements of the Group for the following three years;

C. Determine the facilities to be included in the Joint Transmission System, as provided for in the Pooling Agreement;

D. Investigate and make studies on other matters affecting the Joint Transmission System;

E. Direct such studies as may be required by the above duties, making use when possible of existing engineering staffs of and studies by the Participating Systems, but as necessary directly employing consultants or other technical personnel;

F. Establish, in conjunction with the owners and/or operators of such facilities, minimum operation and maintenance standards for the facilities included in the Joint Transmission System;

G. Establish rules and regulations relating to economy energy transfers.

Operating Committee

The Operating Committee of the Missouri Basin Systems Group is responsible for pool operations. The Operating Committee consists of representatives of each system or group of systems operating or maintaining generating facilities or transmission facilities which are connected to the Joint Transmission System or are part of the Joint Transmission System.

In general, the Operating Committee establishes general guides relating to dispatching and other operating maters, makes operating studies where coordination or uniformity is necessary or desirable because of inter-system connections and transactions, determines reserve responsibilities of the parties from time to time, coordinates scheduled outages of generation facilities, determines the availability of surplus capacity in the Joint Transmission System for deliveries of economy energy, and such other pool operating responsibilities as may be assigned.

At the present time, the membership of the Operating Committee consists of a representative of the U.S. Bureau of Reclamation and a representative of Basin Electric Power Cooperative.

Subcommittees

Under the Planning Committee, subcommittees are established from time to time to perform activities and develop recommendations to the Planning Committee on specific subjects. Among the existing subcommittees are the following: the Major Systems Studies Subcommittee; the Municipal Systems Subcommittee; the Transformation Subcommittee; and the Subcommittee on Joint System Additions. Five MBSG representatives participate in the Inter-System Coordinating Committee. Added to this list is the "Power Supply Subcommittee" whose duties and recent activities is described on page IV–C–43.

Operation of the Missouri Basin Systems Group

The operations of the Missouri Basin Systems Group are governed by the Missouri Basin Systems Group Pooling Agreement. This Agreement has been executed by all members of the Systems Group and sets forth in some detail the policies, procedures, voting representation and methods of arriving at decisions within the Systems Group.

The Pooling Agreement states that the members of the Systems Group intend to coordinate their system planning and operation, to the extent each member finds it desirable and practicable to do so, for their mutual advantage and the public benefit, such coordination to include the following:

A. Coordination of studies relating to the addition of generation and transmission facilities in the area;
B. Coordination and transmission services over the facilities of the members of the Systems Group, including the United States, the charges therefore and the policies governing such transmission;
C. Coordination and maintenance of reserve generating and transmission capacity; and
D. Coordination and the sales of surplus energy.

As far as conduct of the business of the Systems Group is concerned, each signatory to the Pooling Agreement designates one representative to vote for it at all meetings of the Group. Generation and transmission cooperatives or similar organizations have one vote for each member distribution cooperative or member public power district. Independent distribution cooperatives, municipal electric systems, public power districts, and state agencies each have one vote, and the United States has one vote. The vote of the majority of such representatives present at a meeting of the Systems Group is deciding, except that none of the provisions in the Pooling Agreement can be changed by the decisions of any such meeting or in any other way except by amendments to the Pooling Agreement which are executed by the signatories. For a valid meeting of the Systems Group, fifty-one percent of the votes must be present.

The Planning Committee arrives at decisions through votes of the duly designated representatives. As indicated above, the Planning Committee cannot change the procedures and policies provided for in the Pooling Agreement.

Planning and Development of Facilities

The planning of additional generation or transmission facilities to be connected to or added to the Joint System is done through the Major Systems Studies Subcommittee of the Planning Committee. This Subcommittee has conducted one major study and several subordinate ones in the past three and one-half years. The major study was the most comprehensive, detailed study ever made of the power needs and resources of the Missouri Basin Area to the year 1980. This is MBSG Study No. 134, and copies of it have been made available to the Federal Power Commission.

Additional studies have been made from time to time, including a study of the effects of adding a second thermal generating unit in the area of Stanton, North Dakota.

The major study referred to above has provided the frame-work within which members of the Systems Group can develop plans for specific additions which they propose to make.

In making such studies, load forecasts are obtained from all members of the Systems Group, plus load forecasts from other utilities in the area. Likewise, the members and other utilities are asked to indicate their plans for additional generation and transmission during the period under study. These data are used as the basis for joint engineering studies to ascertain the best alternative ways of adding generation and transmission to meet the forecasted future power requirements of the members.

A member of the Systems Group proposing to add generation or major transmission is expected to bring his proposals and detailed engineering data to the Major Systems Studies Subcommittee for review and evaluation. The Subcommittee reports to the Planning Committee its recommendations, including whether the proposed facilities should be approved by the Planning Committee for inclusion in the Joint Transmission System or for connection to the Joint Transmission System.

With respect to reserves, the Pooling Agreement provides that reserve capacity requirements will be pooled, and each system owning generation will be responsible for providing an equitable share of the total reserve capacity. It provides further that total reserve capacity shall be 10% of total hydro capacity required for load, plus 12% of total thermal capacity required for load. The division of reserve responsibility at any time is determined under the direction of the Operating Committee. Any proposal by a Systems Group member to add generation to the Joint System must include adequate provision for reserve capacity before it can be recommended by the Major Systems Studies Subcommittee or approved by the Planning Committee.

Coordinated system stability studies are made annually by the Major Systems Studies Subcommittee and the findings reported to the Planning Committee and Systems Group. This annual study looks three years ahead to ascertain whether the Joint Transmission System will have adequate capacity and satisfactory stability for the three-year period.

Operating Practices

Under the Pooling Agreement, members of the Systems Group which are also Participating Systems in the Pool can exchange capacity and energy under the terms of the Pooling Agreement and the general supervision of the Operating Committee.

The coordination of reserves, including spinning reserves, is provided for as indicated above.

The coordination of maintenance is also performed by the members of the Operating Committee. The economic dispatch of energy is under the general supervision of the Operating Committee.

Day-to-day operations are conducted by the Bureau of Reclamation's control center at Watertown, South Dakota. The only participating system other than the Bureau at the present time is Basin Electric Power Cooperative. The 216,000 kw thermal generating unit of Basin Electric is tied in to the Watertown control center by appropriate communication facilities so that the power and energy from the thermal unit is dispatched out of Watertown along with the output of the Federal hydro plants on the Missouri River. The level of generation of this thermal unit is under the control of Watertown in the same way as is the production level of each of the hydro facilities owned by the Federal government, under energy marketing and interchange provisions which provide incentives to both parties to operate the thermal and the hydro units in the most economical manner.

Power Supply Subcommittee

This committee was assigned the responsibility of developing plans for bulk power supply and transmission that would serve the additional power needs of the majority of the members of the Missouri Basin Systems Group. A regional plan was developed which involved coordination between Basin Electric Power Cooperative, Consumers Public Power District and the United States Bureau of Reclamation with respect to timing of installation of generating facilities, purchase of hydro peaking capability and sharing of reserves. In view of the size of the proposed generating facilities, it was necessary to go outside the MBSG pool to secure backup for a portion of the Consumers proposed 800 mw nuclear unit.

Coordination between the MAPP planning organization and the MBSG Planning Committee has been inadequate, as the transmission studies involving back-up for the 800 mw nuclear unit whose output will be used in both the Iowa Pool (MAPP) and the Nebraska system (MBSG) have been carried out separately by MAPP and MBSG. An area for significant coordination between MAPP and MBSG exists in the implementation of the regional power plan developed through the Missouri Basin Systems Group.

MBSG MEMBER SYSTEMS

	1967 peak loads (MW)
U.S. Bureau of Reclamation	746
COLORADO:	
Tri-State G&T	[1] 259
IOWA:	
Town of Akron	1
Town of Alta	1
City of Anita	1
Atlantic Municipal Utilities	8
Town of Breda	(3)
Coon Rapids Municipal Utilities	2
Corn Belt Power Cooperative	85
City of Corning	2
Denison Municipal Utilities	7
Gowrie Municipal Light Plant	(2)
Graetinger Municipal Light Plant	1
Harlan Municipal Utilities (includes Shelby)	5
City of Hartley	1
City of Hawarden	3
Town of Kimbalton	(3)
Lake Park Municipal Utilities	1
Town of Lake View	2
Lennox Municipal Light Plant	1
L&O Power Cooperative	18
Manning Municipal Light Plant	2
Manilla Municipal Power Plant	1
Mapleton Municipal Electric Plant	1
Milford Municipal Light Plant	1
Northwest Iowa Power Cooperative	61
City of Onawa (includes Blencoe)	3
Orange City Municipal Utilities	3
Town of Paullina	1
Town of Primghar	1
Town of Remsen Municipal Utilities	1
City of Rock Rapids	2
Town of Sanborn	1
Town of Shelby (see Harlan)	(3)
City of Sibley (includes Bigelow)	4
Spencer Municipal Utilities	10
Town of Stanton	1
Village of Villisca	1
Town of Wall Lake	1
Woodbine Light & Power	1
NORTH DAKOTA:	
Basin Electric Power Cooperative	
City of Cavalier	2
Central Power Electric Cooperative	78
Dakotas Electric Cooperative	52
City of Grafton	5
City of Hankinson	(2)
City of Hillsboro	1

	1967 peak loads (MW)
NORTH DAKOTA—Continued	
City of Hope	(3)
City of Lakota	1
City of Maddock	(2)
Mor-Gran-Sou Electric Cooperative	8
Sharon Village Light & Power Department	(3)
Sheyenne Valley Electric Cooperative	(2)
City of Valley City	8
Verendrye Electric Cooperative (included in Central G&T)	
SOUTH DAKOTA:	
City of Aberdeen	1
City of Arlington	1
Town of Badger	(3)
City of Beresford	1
City of Big Stone City	(3)
City of Burke	1
Cherry-Todd Electric Cooperative	4
East River Electric Power Cooperative	135
City of Elk Point	1
City of Estelline	1
City of Faith	1
City of Fort Pierre	1
Grand Electric Cooperative	6
Town of Langford	(3)
City of Madison	5
City of Miller	2
Moreau-Grand Electric Cooperative	5
City of Parker	1
City of Pierre	11
Rushmore Electric Power Cooperative (includes Tri-County)	41
City of Tyndall	1
City of Vermillion	5
City of Volga	1
Watertown Municipal Utility Board	12
City of Wessington Springs	1
KANSAS:	
Flint Hills Rural Electric Cooperative	9
Kansas Electric Cooperative	(2)
MINNESOTA:	
City of Alexandria	8
Village of Brewster	(3)
Town of Elbow Lake	1
Village of Fairfax	1
Village of Grove City (see Litchfield).	
Village of Henning	1
City of Jackson (includes Alpha)	3
Lakefield Public Utilities	1
City of Litchfield (includes Grove City)	8

See footnotes at end of table.

MBSG MEMBER SYSTEMS—Continued

	1967 peak loads (MW)
MINNESOTA—Continued	
City of Melrose	3
Minnesota Valley Cooperative	17
Mountain Lake Municipal Utilities	2
Public Utilities Commission	([2])
Renville-Sibley Cooperative	7
Village of Stephen	1
Village of Tyler	1
Village of Wadena	4
Westbrook Municipal Light & Power	1
MONTANA:	
Big Flat Electric Cooperative	([1, 4])
Central Montana G & T (partially served by MPC)	[1] 32
Hill County Electric Cooperative	([1, 5])
McCone Electric Cooperative (Mosby only)	([1, 2, 6])
Marias River Electric Cooperative	([1, 4])
Park Electric Cooperative	([1, 5])
MONTANA—Continued	
Upper Missouri G & T	45
Yellowstone Valley Electric Cooperative	([1, 5])
NEBRASKA:	
Beatrice Board of Public Works (12 included under NPPS)	3
Board of Regents, University of Nebraska	11
Village of Callaway	([3])
City of Grand Island	40
City of Nebraska City	12
Nebraska Department of Public Institutions	4
Nebraska Public Power System	([7])
The Central Nebraska Public Power & Irrigation Dist	([7])
Platte Valley Public Power & Irrigation Dist.	([7])
Loup River Public Power Dist	([7])
Nebraska Electric G & T	([7])

MBSG MEMBERS—Generation Data

	Capability (MW) Generation
U.S. Bureau of Reclamation	2, 048
Corn Belt Power Cooperative	116
Central Power Electric Cooperative	38
Municipal Utilities	[8] 205
Basin Electric Power Cooperative	216

[1] Not in FPC Regions 26 or 27.

[2] Information not available.

[3] System peak of less than 500 KW.

[4] Included in CMG &T.

[5] Partially included in CMG &T—remainder furnished by MPC.

[6] Total load furnished by MPC.

[7] Refer to Coordinated Planning and Development—Appendix A; Page 2.

[8] Total generation of MBSG member municipals.

NOTE.—All load data shown is at load.

Nebraska Public Power System

Nebraska Public Power System coordinates and dispatches the operation of the generation and transmission facilities of the following entities in east-central Nebraska:

Loup River Public Power District
Platte Valley Public Power and Irrigation District
The Central Nebraska Public Power and Irrigation District
Consumers Public Power District

In addition, Nebraska Public Power System serves as the control area utility for the following municipals and State agencies:

Village of Arnold
City of Auburn
Village of Blue Hill
City of Broken Bow
Village of Callaway
City of Curtis
Village of Deshler
Village of DeWitt
City of Fairbury
City of Grand Island
City of Hastings
City of Nebraska City
City of Schuyler
City of West Point
Village of Winside
City of Wisner
City of Wahoo
University of Nebraska
State Home—Beatrice
State Hospital—Hastings
State Hospital—Norfolk
State Penitentiary—Lincoln

Nebraska Public Power System has participated in coordinated planning and operation with adjoining systems since 1941 when the outstate Nebraska systems were interconnected with Nebraska Power Company (now Omaha Public Power District) and other utilities in the region.

Nebraska Public Power System is a member of the Southwest Regional Group of the Interconnected Systems Group. NPPS is also an associate member of the Southwest Power Pool and follows the recommended operating practices of the Southwest Regional Group and the Interconnected Systems Group. This arrangement is not a contractual obligation but is a means of voluntary participation in the coordinated activities of these groups in the region.

Through the membership of Loup River Public Power District and Platte Valley Public Power and Irrigation District NPPS participates in the activities of the Missouri Basin Systems Group. Nebraska Public Power System has interconnection agreements with Omaha Public Power District and the United States Bureau of Reclamation and is currently participating in coordination and planning which will integrate NPPS—USBR—Basin Electric operations in the region to effectively utilize the peaking capability of the Missouri River Main Stem hydro plants to meet the seasonal load diversity in the region.

NPPS also has interconnection agreements with the cities of Fairbury, Grand Island, Hastings and Wahoo, Nebraska, which provide for Reserve Interchange Service, Emergency Service, Economy Interchange Service, and related operating arrangements.

The joint operations with the above entities requires definition of control area responsibilities, coordination of reserves, including spinning reserves and regulating capacity, coordinated maintenance schedules together with annual review of load and capacity requirements.

The dispatching of the generation and transmission facilities within reliability and contract limitations, permits effective and economic use of low cost generation as well as exchanges of capacity and energy within the control area and with adjacent utility systems in the region.

Upper Mississippi Valley Power Pool

1. Type of Organization:

   The UMVPP is a planning and operating pool that carries out coordination under a formal agreement.

2–3. History of Development and List of Members:

   The pool agreement became effective on Feb. 10, 1961, with six participating utilities as follows:

	Peak Loads 1967 (MW)	*Jan. 1, 1968 Capability (MW)*
Dairyland Power Cooperative (DPC)	283	305
Minnesota Power & Light Co. (MP&L)	482	511
Northern States Power Co. (Minn) and (Wisc.) (NSP)	2, 323	2, 232
Interstate Power Co. (ISP)	329	564
Otter Tail Power Co. (OTP)	192	280
The original pooling agreement has been amended to provide for memberships of eight additional utilities as follows:		
July 1962—Rural Cooperative Power Asso. (RCPA)	99	150
Dec. 1962—Lake Superior District Power Co. (LSDP)	91	108
Sept 1963—Minnkota Power Cooperative (MPC)	123	45
Dec. 1963—Cooperative Power Asso. (CPA)	196	11
Aug. 1964—Northern Minn. Power Asso. (NMPA)	58	83
Aug. 1964—United Power Asso. (UPA)		[1] 158
May 1965—Northwestern Public Service Co. (NWPS)	98	73
May 1965—Montana-Dakota Utilities Co. (MDU)	157	207
Total	4, 431	4, 727

[1] Included in RCPA and NMPA totals.

Northern States Power Company (Wisc) is a wholly-owned subsidiary of NSP (Minn) and these two corporations are represented as a single entity for purposes of coordination under the pool agreement. Similarly UPA is a corporation formed by RCPA and NMPA to provide certain generation and transmission facilities and its participation under the pooling agreement is restricted to operations and power transactions associated with those facilities.

4. Requirements for Participation:

The pool agreement contains no specific requirements for membership. Its preamble paragraphs establish that the participants are: engaged in the business of generating and transmitting electric energy, operate in contiguous areas with their systems either interconnected or planned to be interconnected, and recognize the mutual benefits of coordinated planning and operation.

5. Organization Structure:

The pool agreement is administered by two separate committees, the Planning Committee and the Operating Committee. Each participant is represented on both committees. In addition, each participant designates an executive officer who represents his utility in an established procedure for review of all recommendations and determinations of both committees.

Each of the committees elects a chairman annually. The chairman appoints such other officers as are deemed necessary by the committee.

The Planning Committee has the broad assignment to carry out or coordinate engineering studies required to develop recommendations for new generating units and transmission facilities in the pool. By way of more specific assignments, it is responsible for development of load forecasts, review of generating reserve requirements, establishment of accredited generation capabilities and scheduling of capacity sales and purchases among the participants in connection with staggering of generator additions.

The Operating Committee is responsible for development and administration of operating practices that will provide optimum operating economy consistent with high reliability of service. Specific areas of operating coordination cited in the pool agreement are spinning reserve, maintenance outages, economy energy transactions, short term load forecasts, determination of interchange energy costs and transmission system operating studies.

An affirmative two-thirds majority vote is required to authorize any determination or recommendations of either committee. Further, all such actions of the committees must be referred to the designated executive officers for a review procedure that permits any participant to protest a committee decision and ultimately invoke the arbitration provision of the pool agreement if necessary to resolve the problem. The authority of the committees and scope of the arbitration clause are expressly limited to the extent that this two-thirds majority voting procedure will not require any participant to install facilities, postpone scheduled maintenance, or accept an amendment to the pool agreement.

6. Practices in Planning and Development of Facilities

(*a*) Coordinated load projections: The Planning Committee maintains a 10 to 15 year forecast of summer and winter peak loads for each participant and the combined pool. Although the members exchange data on growth trends and review forecasting procedures, the ultimate responsibility for load estimates remains with the individual utilities.

(*b*) Coordinated planning for reserves: Currently each participant is required to maintain reserve capacity of at least 12% of its annual peak load. This is subject to change by recommendation of the Planning Committee. The Planning Committee's evaluations of pool reserve requirements have been based on calculated probabilities of capacity loss, accuracy of load forecasts and needs for spare capacity to accommodate generator maintenance.

(*c*) Coordinated system stability studies: At present generation capacity is quite evenly distributed with respect to loads within the pool and there is no heavy transmission over long distances. As a result, transient stability has not been a major consideration in design of the present system. In recent years the pool has participated in a number of stability studies in connection with planning for future facilities. These studies include systems well beyond the pool borders

and the UMVPP involvement has been in the form of participation in studies that are primarily under the sponsorship of other organizations such as MAPP, MAIN, and the Bureau of Reclamation.

(*d*) Joint or staggered participation in facilities development: This item covers the principal activities of the Planning Committee. Coordinated planning efforts are directed toward consolidating load growth requirements for supply from large economical generating units consistent with reliability considerations and additional transmission costs for power distribution from larger concentrations of capacity. In addition to coordinating engineering work behind this generator staggering program, the Planning Committee handles arrangements for the associated power sales and purchases under rate schedules of the pool agreement.

The effectiveness of coordinated generation planning in the UMVPP is demonstrated by the tabulation below which compares the sizes of base load generators now under construction with annual peak loads in the owner's systems at the time of the installations.

Year	Generator size: Megawatts	Generator size: Percent of owners peak load
1966	158	113
1967	216	57
1968	580	23
1969	325	105
1970	500	17
1970	212	130

With regard to transmission facilities, a majority of the lines recently completed or new being constructed in the pool area represent joint development. In general, costs of these projects are shared by division of ownership among the utilities operating in the area of the individual lines.

7. Operating Practices:

(*a*) Exchange of capacity and energy: The pool agreement contains rate schedules for the various capacity and energy transactions contemplated thereunder as follows:

1. Participation Power Interchange Service.
2. Seasonal Participation Power Interchange Service.
3. Emergency and Scheduled Outage Interchange Service.
4. Spinning Reserve Interchange Service.
5. Economy Energy Interchange Service.
6. Wheeling Services and Losses.
7. Operational Control Energy Interchange Service.
8. Peaking Power Interchange Service.
9. Short Term Power Interchange Service.
10. Firm Power Interchange Service.

Schedules A, B, H, I, and J are primarily administered by the Planning Committee in connection with its responsibilities for coordinated generation planning and sharing of reserves as previously discussed.

The remaining service schedules are primarily used by the Operating Committee in carrying on day-by-day coordination as discussed under the remaining sub sections of this item 7. Service Schedule F provides for transmission service between participants whose systems are not directly connected to each other and hence is essentially a supplement to all of the other schedules for this special situation.

(*b*) Coordination of spinning reserves: A minimum pool spinning reserve equal to the largest unit in operation is presently required. This amount of spinning reserve is allocated among the interconnected participants on the basis of largest unit in each system and its annual peak load, equal weight being given to each of these two factors. The Operating Committee designates the system control center of one member utility to act as the Spinning Reserve Coordination Office. That office monitors spinning reserve scheduling and assists in arrangements for transactions under Service Schedule D when appropriate.

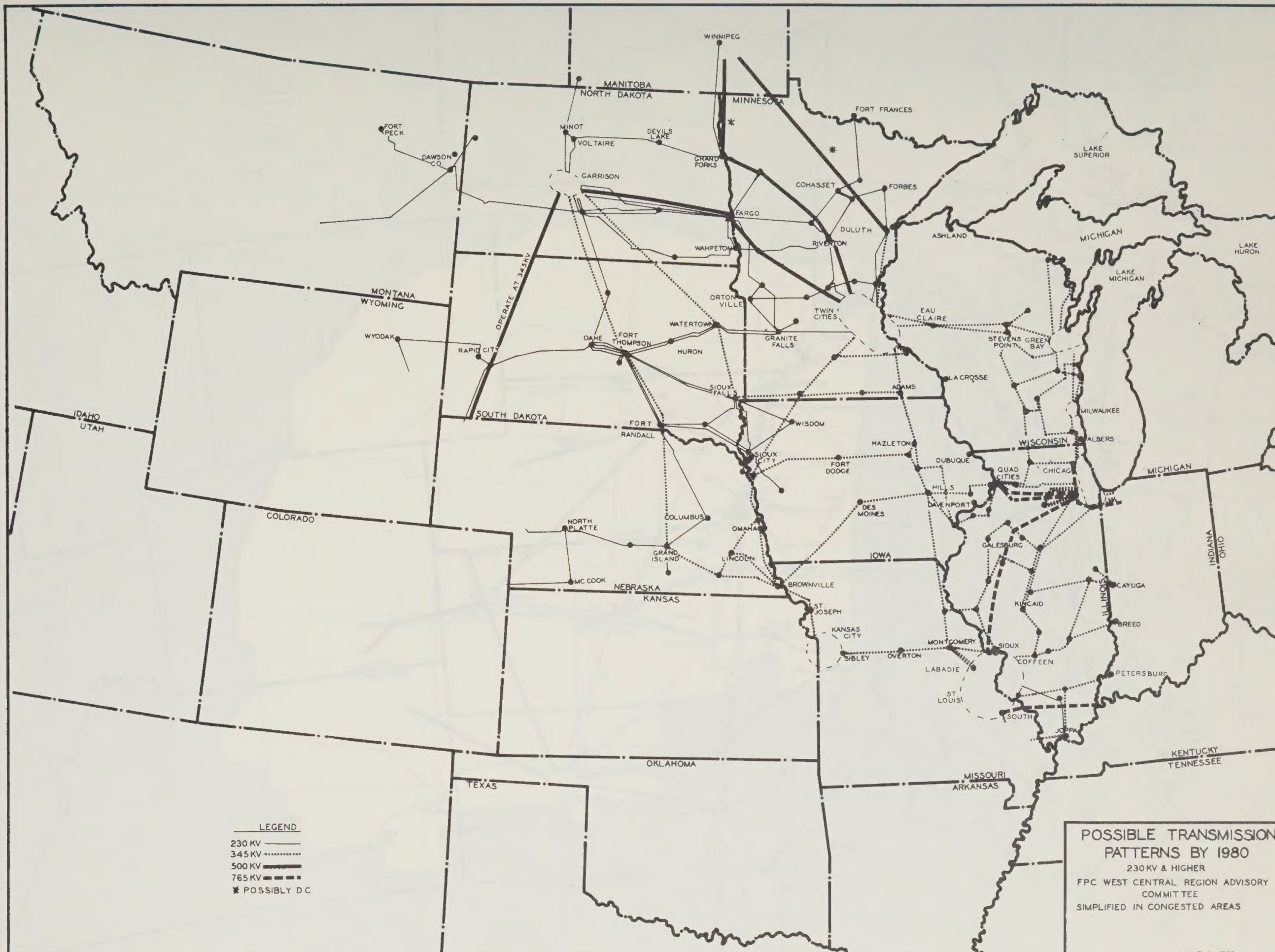
Leased line teletype communications between individual member dispatching offices are used extensively in carrying out close coordination on spinning reserve and other functions of the Operating Committee. These facilities are arranged for office-to-office contacts or multiple addressing to all other offices by any one member.

(*c*) Coordination of maintenance: The Operating Committee maintains an 18-month projection of load-capacity data for use in coordinating maintenance outage at their quarterly meetings. Again, however, one of the utilities is designated as Maintenance Coordinator to provide continuous coordination.

(*d*) Economic dispatch: Economic scheduling of energy production among the pool generating plants is carried out through the use of Service Schedule E—Economy Energy Interchange Service. For the most part, this is handled by daily exchanges of estimated system power production costs for the following day (or weekend) over the teletype network. On any day, transactions are first scheduled between the systems with highest and lowest costs, then between the two systems of next largest cost spread, etc.

Of the pool systems, DPC, ISP, LSDP, MP&L, NSP, OTP, RCPA, and UPA each have tie line load control equipment.


TRANSMISSION SYSTEM BY 1970
230 KV & HIGHER
FPC WEST CENTRAL REGION ADVISORY COMMITTEE
SIMPLIFIED IN CONGESTED AREAS
MAR 3, 1969
LEGEND
230 KV
345 KV
MANITOBA
NORTH DAKOTA
MINNESOTA
MONTANA
WYOMING
IDAHO
UTAH
SOUTH DAKOTA
COLORADO
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
IOWA
MISSOURI
ARKANSAS
WISCONSIN
ILLINOIS
MICHIGAN
INDIANA
OHIO
KENTUCKY
TENNESSEE
LAKE SUPERIOR
LAKE MICHIGAN
LAKE HURON
WINNIPEG
FORT PECK
DAWSON CO.
VOLTAIRE
DEVILS LAKE
GRAND FORKS
WINGER
GARRISON
BISMARCK
FARGO
FORBES
DULUTH
WAHPETON
RIVERTON
TWIN CITIES
EAU CLAIRE
STEVENS POINT
GREEN BAY
WATERTOWN
OAHE
FORT THOMPSON
GRANITE FALLS
NEW UNDERWOOD
SIOUX FALLS
LAKEFIELD JCT
MILWAUKEE
ALBERS
FORT RANDALL
HAZLETON
DUBUQUE
ROCKFORD
SIOUX CITY
QUAD CITIES
CHICAGO
HILLS
DAVENPORT
DES MOINES
NORTH PLATTE
COLUMBUS
OMAHA
GRAND ISLAND
LINCOLN
BROWNVILLE
CAYUGA
ST JOSEPH
KINCAID
BREED
KANSAS CITY
SIBLEY
OVERTON
MONTGOMERY
SIOUX
COFFEEN
LABADIE
ST LOUIS
WEST FRANKFORT
JOPPA


POSSIBLE TRANSMISSION PATTERNS BY 1980
230 KV & HIGHER
FPC WEST CENTRAL REGION ADVISORY COMMITTEE
SIMPLIFIED IN CONGESTED AREAS
MAR 3, 1969
LEGEND
230 KV
345 KV
500 KV
765 KV
* POSSIBLY DC
OPERATE AT 345 KV
WINNIPEG
MANITOBA
NORTH DAKOTA
MINNESOTA
FORT FRANCES
FORT PECK
DAWSON CO.
MINOT
VOLTAIRE
DEVILS LAKE
GRAND FORKS
GARRISON
COHASSET
FORBES
FARGO
DULUTH
LAKE SUPERIOR
ASHLAND
MICHIGAN
LAKE HURON
LAKE MICHIGAN
WAHPETON
RIVERTON
ORTONVILLE
TWIN CITIES
EAU CLAIRE
MONTANA
WYOMING
WYODAK
RAPID CITY
OAHE
FORT THOMPSON
WATERTOWN
HURON
GRANITE FALLS
STEVENS POINT
GREEN BAY
LA CROSSE
SIOUX FALLS
ADAMS
MILWAUKEE
IDAHO
UTAH
SOUTH DAKOTA
FORT RANDALL
WISDOM
HAZLETON
WISCONSIN
ALBERS
SIOUX CITY
FORT DODGE
DUBUQUE
QUAD CITIES
CHICAGO
MICHIGAN
HILLS
DAVENPORT
DES MOINES
COLORADO
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COLUMBUS
OMAHA
GALESBURG
INDIANA
OHIO
GRAND ISLAND
LINCOLN
IOWA
MC COOK
NEBRASKA
KANSAS
BROWNVILLE
CAYUGA
ILLINOIS
ST. JOSEPH
KINCAID
BREED
KANSAS CITY
MONTGOMERY
SIOUX
SIBLEY
OVERTON
COFFEEN
LABADIE
PETERSBURG
ST. LOUIS
SOUTH
JOPPA
KENTUCKY
TENNESSEE
OKLAHOMA
MISSOURI
ARKANSAS
TEXAS

POSSIBLE TRANSMISSION PATTERNS BY 1990
230 KV & HIGHER
FPC WEST CENTRAL REGION ADVISORY COMMITTEE
SIMPLIFIED IN CONGESTED AREAS

THE FUTURE OF POWER IN THE WEST REGION

1970-1980-1990

A Report
To the Federal Power Commission

Prepared by
The West Regional Advisory Committee

June 1969

Letter of Transmittal

The West Regional Advisory Committee submits this report to the Federal Power Commission to assist in updating the National Power Survey. The report, consisting of a summary and appended subcommittee reports, represents the concentrated study of a number of important subjects underlying the region's future power supply for the 1970–1990 period.

The studies and investigations which covered approximately two and a half years resulted in the compilation of subcommittee reports on Future Power Requirements, Fuels, Generation, Transmission, and Coordinated Planning and Development.

Based on the subcommittee studies, the committee as a whole prepared a summary of the salient points developed by the various subcommittees. The summary includes digests of the specialized subcommittee reports.

The summary report contains a foreword section in which certain general conclusions are expressed. The foreword is an integral part of the report and represents the West Regional Advisory Committee's definition and evaluation of some broad general factors which will significantly affect the utility industry in the West during the next twenty years.

The Committee expresses its appreciation to the many individuals that have contributed to this report. Members on task forces and subcommittees responsible for this work appear in the section on Memberships.

THE WEST REGIONAL ADVISORY COMMITTEE

FOREWORD

The section of the United States which comprises the West Region is one of the most dynamic areas in the United States. The rate of growth in much of the area exceeds that of the rest of the nation. The utilities serving this area are justifiably proud of their performance in keeping pace with the region's power requirements in past years and of their demonstrated ability to provide power at the lowest reasonable cost and in the highest order of reliability. These utilities are dedicated to continue to serve the public in an equally efficient and effective manner in the future.

To meet the projected 1990 requirements for bulk power supply, the region's utilities will need to invest several billion dollars in additional generating and transmission facilities. It is estimated that the regional loads will increase from 54,000 megawatts in 1970 to 216,000 megawatts in 1990. Its resources will increase from 66,700 megawatts in 1970 to 254,000 megawatts in 1990. The composition of the generating systems will change from 52 percent thermal in 1970 to 74 percent thermal in 1990. To effect an orderly transition from a system dominated by hydroelectric facilities to one dominated by thermal facilities, and to make the best use of the additional investment in generating and transmission plant contemplated by the report will require a high degree of coordinated planning among the region's utilities. One of the principal factors which the utilities will consider as they plan for the future is bulk power supply reliability. Utilities in the region intend to pursue such coordination of planning and to work toward effective pooling of regional resources.

Projections of loads for the next twenty years should not be considered as precise forecasts. The wide range of variables which affect load growth cannot accurately be predicted and the load and resource levels estimated for 1990 should be considered as orders of magnitude only.

It is the industry's intention to continue to provide power in sufficient quantity and at the lowest reasonable cost. It should clearly be understood, however, that a number of factors external to the operation of the utilities may have a greater effect on costs than those internal factors which the industry can control. Controllable factors which have a tendency to reduce unit costs of power and energy include mechanization, installation of large generating units, strong interconnections, coordinated operation, power pooling and joint planning. Factors outside the industry which tend to offset lower unit costs are inflation, rising costs of money, and the growing and persistent desires of our society relating to environmental quality control. It is no longer adequate for the industry to provide only high quality service of utmost dependability and at the lowest reasonable cost—standards which the utility industry has met in the past. It is now necessary to recognize that society requires these standards, plus an avoidance of air and water pollution, establishment of recreational facilities, recognition of esthetic values in design of utility plant and preservation of the natural beauty of undeveloped areas.

Meeting these new requirements has a substantial price tag, but one which cannot be quantified at this time. We can be sure, however, that additional costs will be imposed upon the industry. It is unrealistic to assume that technological improvements can fully offset additional costs imposed by external pressures. The West Region,

therefore, does not project a decrease in the cost of power over the twenty-year period. The region's utilities, however, will continue to emphasize their efforts to obtain economies wherever possible in order to minimize the upward pressure on cost of energy.

THE WEST REGIONAL ADVISORY COMMITTEE

CONTENTS

CHARTS, TABLES, FIGURES AND MAPS

Summary

Appendix

West Region Subcommittee Reports

356-240 O—70——18

THE FUTURE OF POWER IN THE WEST REGION

Fully one-third of the contiguous United States lies within what has been designated for this study by the FPC as the West Region.[1] Because this region covers such a large area, it cannot be simply characterized in terms of climate, geology, economy, or sociology. Power systems have been developed which strongly reflect the heterogeneous character of the region. The pictorial maps which follow provide a rapid means of obtaining an overall view of the items of importance to the existing and projected power requirements and development.

Existing load centers in the region are shown in Figure 1. The proportionate sizes of the loads at load centers are expected to be about the same in 1990. The estimated loads for 1970 are 54,035 megawatts and 307,759 gigawatthours. By 1990 they will quadruple to 216,420 megawatts and 1,232,800 gigawatthours. The large loads along the Pacific Coast and the long distances between load centers are key characteristics.

Figure 2 shows the distribution of the region's natural resources available for the production of electricity and indicates the three subregion study areas used by the Fuels Task Force in its report. The variety and non-uniform distribution of natural resources are of significance to the economics of electric generation installed and projected for the region.

The pattern of generation for the region is expected to change significantly between 1970 and 1990. Symbols shown on Figures 3 and 4 signify installations of hydro, fossil-fueled, and nuclear-fueled capacity for 1970 and a possible mix of generation for 1990. Comparison of the two maps clearly demonstrates the projected large increase in nuclear-fueled capacity along the coast and serves to emphasize the expected change in power de-

[1] Includes portions of FPC regions, V, VI, VII & VIII.

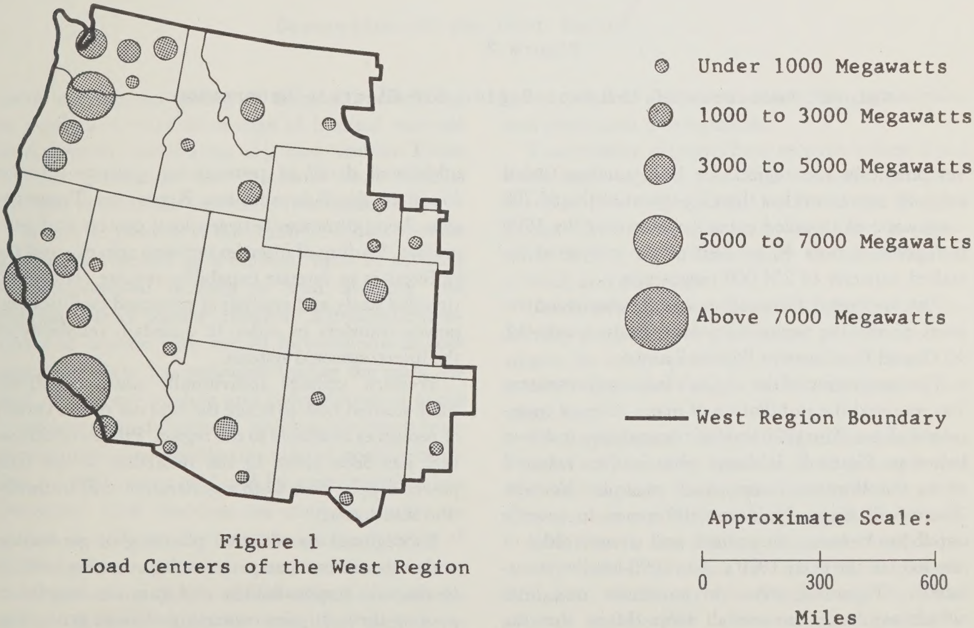

Figure 1
Load Centers of the West Region

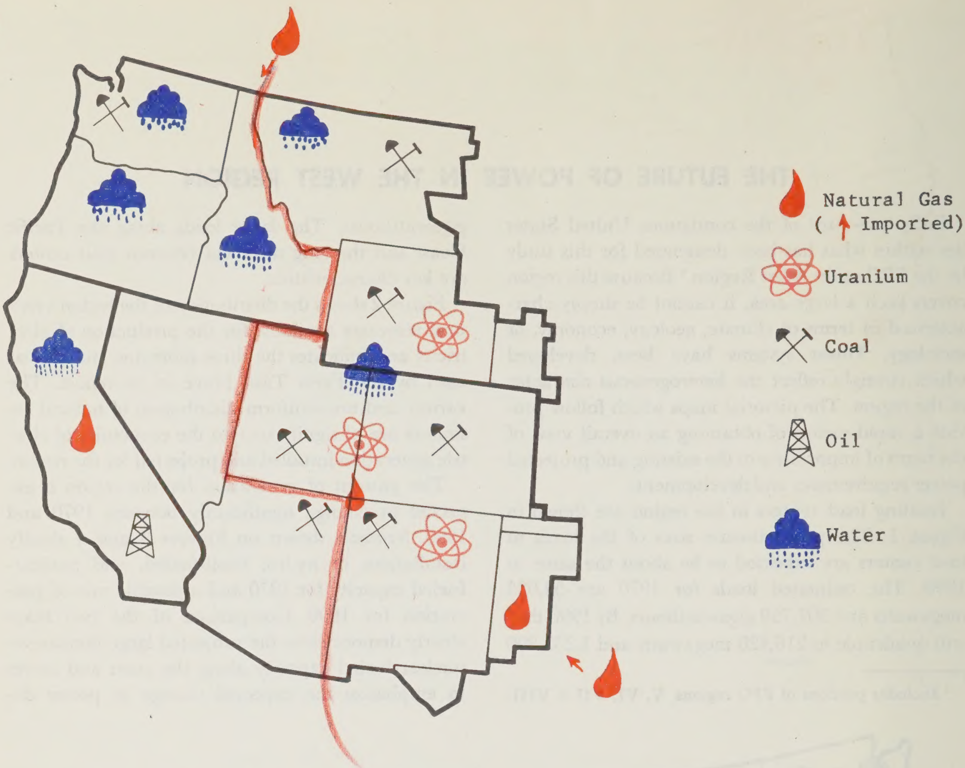

Figure 2

Natural Resources of the West Region for Electric Generation.

velopment in the region. In 1970 nuclear-fueled capacity represents less than 2 percent of the 66,700 megawatts of installed capacity. However, by 1990 it represents over 40 percent of the projected installed capacity of 254,000 megawatts.

The appended Generation and Transmission reports divide the region into four study areas—M, N, O, and P—shown in Figures 3 and 4.

The integration of the region's loads and resources has required the installation of many miles of transmission lines. The 1970 level of transmission is shown below on Figure 5. It shows what is often referred to as the Western Loop which encircles Nevada. There will be a significant difference in intertie capability between the eastern and western sides of the loop in the early 1970's. The 1990 level of transmission, Figure 6, shows in particular new lines which reinforce the overall loop. Maps showing additional detail of transmission patterns can be found in the Subcommittee Report on Transmission. Long distances between load centers and generation, loading of interties between systems, and the differences in intertie capability require continuing detailed study and analysis of proposed facilities and power transfers in order to maintain reliability of the interconnected systems.

Western utilities individually and collectively have studied how to make the best use of the variety of resources available to the region. Prime consideration has been given to the reliability of the bulk power supply from both a generation and transmission standpoint.

Subregional coordinated planning of generation and transmission has permitted generating utilities to share in responsibilities and gain the benefits of pooling through joint ownership of large generating

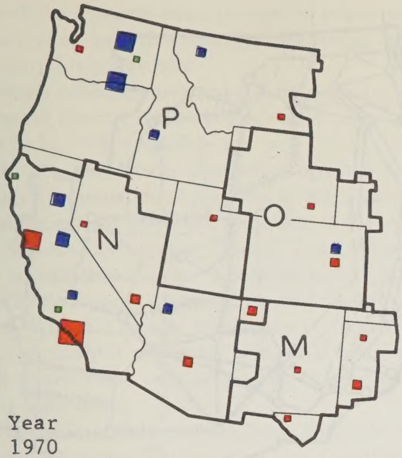

Figure 3

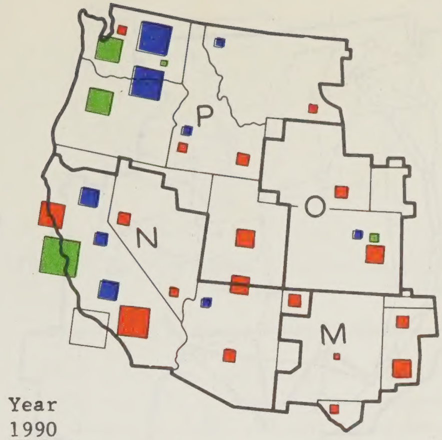

Figure 4

Under 1000 MW

1000 - 3000 MW

3000 - 5000 MW

5000 - 10,000 MW

10,000 - 15,000 MW

15,000 - 20,000 MW

Above 20,000 MW

Hydro

Fossil Fueled

Nuclear

Generation of the West Region

units, coordinated timing of units and scheduling of overhaul to take advantage of internal seasonal load diversity, and sharing of pooled reserves. Those without generation have received such benefits through appropriate wholesale (for resale) rates.

It may be possible in the future to reduce further generating reserves on a regional basis by utilizing any incremental benefits in load diversity and regional reserve pooling. However, a prudent atmosphere of caution with regard to reduction in generation reserves has prevailed during the early period of regional pooling and coordination to avoid possible reserve deficiencies which might result from overestimating or double counting of pooling benefits. An EEI report on Load Diversity published in December 1968 describes the complex studies required to evaluate the extent to which diversity of loads between systems can be used to reduce or defer generation. Regional and subregional coordination efforts to obtain the benefits of pooling require detailed analysis of alternative transmission and generation developments.

Transmission planners have recently enlarged and made more sophisticated their computer programs for load flow and stability studies of the Western Loop. These programs have been used to determine tie line capabilities under various conditions of loads and generation.

Generation planners have developed special reliability programs using advanced probability techniques to study potential reserve reductions for pooled operation which reflect interconnection capacities.

The hypothetical example diagrammed in Figure 7 shows why in many cases the usual assumption of "infinite" capacity interconnections cannot be made. The numbers represent units of capacity or demand.

With the tie line loading assumed, Area B has a very limited potential for reducing its reserve. Situations similar to this diagram can be found where considerable distances or geographic

Figure 5--1970

Figure 6--1990

Electric Transmission in the West Region

---- 230 kV
+++++++ 287 and 345 kV

——— 500 kV and above
— — 750 kV D.C.

A ——→ B

Interconnection capability	1200*
Firm Transfer	- 1000
Reserve transfer capability	200
Inaccessible reserve (2000 - 200)	1800

A

Generation	10,000
Load	7,000
Firm Transfer Out of Area	1,000
Reserve	2,000

Interconnection Capability 1200* ←→

Firm Transfer 1000 ——→

B

Generation	8,000
Load	7,000
Firm Transfer Into Area	1,000
Reserve	2,000

Non-delivery of firm transfer	1000
Remaining reserve in Area B	1000
Reserve transfer capability	2000

A ←—— B

* Interconnection capacity established by stability or thermal limits.

Figure 7

Reserve Transfers for Pooled Operation

boundaries separate large systems or power pools which often possess internally very strong transmission grids of their own.

Simply stated, an area which loads a tie line with imported power cannot use the loaded capacity of that tie for reserve support.

On a regional basis excellent progress is being made in coordination of planning and development of power systems under the leadership of the Western Systems Coordinating Council. Load, resource, and transmission data are now being exchanged by utilities throughout the region on the broadest scale ever. With this greater availability of data, more detailed analyses of possible additional benefits of load diversity and regional pooling of reserves are being undertaken.

Summaries of the reports on Power Requirements, Fuels, Generation, Transmission, and Coordinated Planning and Development follow in the order indicated. They extract the most important considerations from, and provide a good reference to, the material covered by the appended subcommittee reports.

Future Power Requirements

General

The estimated future power requirements for the West Region were developed from the projected power requirements of the 13 Western Power Supply Areas (PSA). The projections were based on trends of load growth supplemented by analyses of factors within each PSA. They were developed by the FPC San Francisco and Fort Worth Regional Office staffs in cooperation with a utility task force. They were approved by the West Region Advisory Committee at its ninth meeting, October 4, 1967, following review and revisions of initial estimates submitted to the Committee. Figure 8 shows the area included in the West Region and indicates the FPC Power Supply Areas.

The present estimate of West Region future power requirements indicates a growth rate greater than that shown in the 1964 National Power Survey. This increased rate of growth follows a trend similar to that of the total electric energy growth in the contiguous United States. In 1965 the energy requirements of the West Region amounted to about 20% of the total for the nation. In 1990 the percentage is expected to be about 21%.

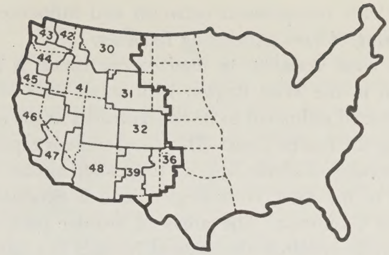

Figure 8. The West Regions With Power Supply Areas Indicated.

Annual and Seasonal Power Requirements

Total energy requirements for the West Region in 1965 were 212,550 gwh with a corresponding peak demand of 37,545 mw, and a load factor of 64.6%. For 1990 these are estimated at 1,232,800 gwh, 216,420 mw, and a load factor of 65.0%. Over this 25-year period this represents an energy growth of 5.8 times and an average compound rate of growth of 7.3%.

The West Region's area, covering more than one-third of the contiguous United States, includes seacoast, mountainous, and desert areas. All types of weather and economic conditions are experienced. Thus wide differences in power usage are experienced now and are to be expected in the future. These differences in power requirements result in some peak load diversity. In 1965 the summer peaks occurred in June, July, or August and the winter peaks occurred in December or January. Similarly, the future summer and winter peaks may be expected to occur in these same months.

The ratio of recorded minimum monthly peak to annual peak for the total West Region was 89% in 1960 and is estimated to be 87% in 1990 with December continuing to be the peak month (calendar year basis).

Principal Load Centers

The tremendous growth of the electric power industry in the decades ahead presents a continuing opportunity for the industry to expand its power systems to take advantage of potential economies in planning future electric power facilities. Familiarity with the distribution and concentration of loads and power needs is important in system planning studies of generation and transmission facilities. Load centers are generally key points on

backbone transmission networks and influence the locating of new generating facilities.

A wide variation in load concentration is indicated in the West Region with about 70% of the 1970 load estimated to be concentrated in the areas along the Pacific Coast. This percentage is expected to increase to about 72% by 1990 when almost one-half of the total West Region load is expected to be in California. The areas of heavier load concentration encircle the State of Nevada in a pattern corresponding to the Western loop formed by the main backbone transmission networks in the West Region.

Classified Sales

An analysis of projected load growth by major use categories gives an indication of the individual area's and Region's economy as well as the direction of future growth. These major use categories are broadly defined as rural and residential, commercial, industrial, and all other. Past and estimated future energy requirements by class of service for PSA's and the West Region were developed to 1990. Although it is difficult to predict with assurance the development of new products and their estimated power requirements in long-range projections, the effect of new uses of electric power is reflected throughout these projections.

The industrial load classification was the largest use category in 1965, accounting for 72,600 gigawatt-hours (over 34% of the total West Region use). Through 1990 it will continue to be the largest use category, maintaining about the same percentage relationship (34.4%) to the total. For the total West Region, the percentage use of the rural and residential class of service is expected to decrease from 30.3% to 28.2% from 1965 to 1990. The commercial class is also estimated to decline in its percentage share from 20.3% to 18.9%. Losses are expected to remain at about 10% of the load. The remainder, Street and Highway Lighting, Electrified Transportation and All Others constitutes 5.4% of total energy requirements in 1965, but due to a marked increase forecast for the All Other classification, energy for this remaining group will be 8.3% of the 1990 West total.

Utility Load Curves

A utility's load curve, a chart showing the power supplied plotted against the time of occurrence, illustrates the varying magnitude of the utility's power demands over a certain period of time.

A typical West Region summer load curve [2] has two separate peaks, with the system peak occurring between 1:00 and 2:00 p.m. and with the secondary peak between 7:00 and 8:00 p.m. due to the early evening residential loads. A typical winter load curve [2] also has two separate peaks with the evening peak load considerably greater than the mid-morning peak. A smooth curve, indicating high demands over a long period of time, is typical of the summer peak while the winter peak is sharp and of short duration.

Energy Supply and Demand

The West Region utilizes a complex mix of energy sources for electrical power generation. Hydroelectric generation has satisfied most of the electrical power requirements of the West Region in the past, and is expected to continue to grow in absolute amount, particularly in the Northwest Subregion, throughout the forecast period. However, thermal generation is projected to exceed hydro generation before 1975, and assume an ever increasing share of the total load thereafter. This projection is based on a survey of West Region utilities, which collected historical data and individual utilities' projections to the year 1990 on the distribution, production, and consumption of fuels, particularly as they are used for the generation of electric power. The principal findings of the survey for the Region as a whole are summarized in tabular form in Figure 9.

The survey disclosed that by 1990, total use of raw energy in the West Region compared with 1970 is expected to more than double. This growing demand will require an input for all uses including electric generation of 22,608 trillion BTU's in 1990 as compared with 10,721 trillion BTU's in 1970. Electric generation will increase four-fold and production of electricity by thermal plants will increase by a factor of about 7.

Oil and gas have been the fuels used for a major portion of the Region's thermal generation; however, coal and nuclear-fueled plants are expected to satisfy the bulk of the increase in generation after 1970. Most of the nuclear generation will be installed in California and the Northwest Subregions.

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[2] See figures 4 and 5 in the appended Future Power Requirements Subcommittee Report.

Coal fired plants will be built outside the California Subregion, but about half of the future increase in coal generation in the Rocky Mountain Subregion will serve loads in California.

In addition to the economic aspects of alternative fuel selections, governmental and regulatory agency policy at the Federal, State and Local levels—in relation to air and water pollution control, water utilization, natural gas regulation, oil imports control, nuclear plant siting, electric systems reliability and energy policy coordination—have a profound influence in shaping the Region's fuel mix. For example, air pollution control considerations have forced utilities in Southern California to substitute premium-priced, foreign low-sulfur fuel oils for domestic residual fuel oils and substantially limit the future use of coal fuel within the state. The limited availability of water for thermal power plant use in the Southwest portion of the Rocky Mountain Subregion may limit the amount of new coal-fired

FIGURE 9

Summary for 1968 West Region Survey of Fuels for Electric Generation—National Power Survey

	1965		1970		1980		1990	
	Quantity	Percent of total	Quantity	Percent of total	Quantity	Percent of total	Quantity	Percent of total
1. Population (Thousands)	31,006	....	34,650	....	43,400	....	54,241	....
2. Total Energy Use (10^{12} Btu)	8,904	100	10,721	100	15,585	100	22,608	100
% Consumed for Electric Generation		25	....	29	....	39	....	52
% Consumed for Thermal Elec. Generation		11	....	14	....	28	....	43
3. Total Elec. Utility Generation (10^9 kwh)	209	100	308	100	631	100	1,205	100
Thermal Elec. Utility Generation (10^9 kwh)	89	43	149	48	447	71	1,007	84
4. Fuel Use for Thermal Elec. Utility Generation (Equivalent Trillion Btu's)	924	100	1,469	100	4,228	100	9,767	100
(a) Coal (Thousand short tons)	7,729	14	15,496	20	59,264	28	93,536	21
(b) Natural Gas (Billion cubic feet)	628	72	855	63	685	17	724	8
(c) Uranium (Short tons U_3O_8)	14	1	1,027	5	8,175	47	15,640	67
(d) Thorium (Short tons ThO_2)					3	....	100	1
(e) Oil, No. 6 (Thousand bbl.)	18,555	13	7,705	4	1,400	....	1,425	....
(f) Oil, Low Sulfur (Thousand bbl.)			16,000	8	49,375	8	46,000	3
5. Average Heat Rate, Fossil Fueled Thermal Elec. Generation (Btu/kwh)	10,412	....	9,865	....	9,471	....	9,718	....
6. Fuel Price Estimates (¢/M² Btu), excluding Transmission:								
(a) Coal	16		15		16		17	
(b) Natural Gas	30		31		34		36	
(c) Uranium	26		20		15		13	
(d) Thorium			20		15		13	
(e) Oil, No. 6	32		32		28		32	
(f) Oil, Low Sulfur			41		42		44	
7. Fuel Reserves:								
(a) Coal (Million Short Tons, 1968) 263,230								
(b) Natural Gas (Billion Cubic Ft., 1966) 30,464								
(c) Uranium (Short Tons U_3O_8, 1968) 148,000								
(d) Thorium (Short Tons ThO_2, 1968) 100,000								
(e) Oil, No. 6 (Million bbl., 1966) (15% of Crude & Shale Oil Reserves) 101,026								
(f) Low Sulfur Oil (Million bbl.)								

generation which can be installed to utilize the substantial, low-priced coal reserves available in that area. Delays experienced in obtaining site approvals for nuclear power plants have required some utilities to delay scheduling the construction of such facilities and in their place construct additional fossil-fueled facilities.

By the mid 1970's the use of natural gas for electric generation in the West Region is expected to begin a proportionate decline as a result of supply and pricing factors. The net internal supply of gas is below demand, and it is increasingly necessary to import gas from Canada and Texas. Projections suggest that annual consumption may exceed annual additions to natural gas reserves available to the West Region by about 1985.

Requirements for fuel oil for electric generation in the West Region are expected to more than double to about 50 million barrels by 1975 and, even though total oil and gas fuel requirements are projected to decline thereafter, oil demand should remain relatively constant through 1990 because of the projected decline in natural gas availability.

The bulk of the fuel oil used in the West Region is confined to the California Subregion and is consumed during periods when the natural gas supply is interrupted by the gas utility suppliers to serve higher priority customers. Several large utilities in California have switched from the use of conventional residual fuel oil to low-sulfur fuel oil to cooperate with [3] air pollution control authorities.

Western domestic petroleum resources, including Alaska, cannot currently supply the demand for low-sulfur fuel oil. Thus, it is assumed allocations of permits to import low-sulfur crude oil into the West Region will continue to be issued by the Oil Import Administration. Possibly low-sulfur synthetic fuel produced from coal, oil shale, or bituminous sandstone deposits may supply a portion of the fuel requirements in the future. This will, of course, depend upon technical and economic factors.

Conventional and low-sulfur fuel oil are frequently incompatible and cannot be stored or handled together. If a decision is made to convert a plant using conventional oil to low-sulfur oil, several plant components, including the storage and handling system, may have to be changed at a considerable cost.

[3] The Los Angeles Air Pollution Control District recently enacted its Rule 62.2 which effectively compels the use of low-sulfur fuel oil (less than 0.5% sulfur by weight) when gas supplies are not available.

It should also be borne in mind that as long as the demand exceeds the domestic supply of fuel oil, companies using either low-sulfur or regular residual fuel oil run the risk of having the supply curtailed in case of international problems, foreign strikes, or other matters beyond control of the United States. If this were to happen, refinery balances would have to be changed because current local production would have been adjusted to reflect the displacement of regular residual oil by imported low-sulfur fuel.

The use of coal for electric generation has increased substantially over the past few years. This growth is expected to continue throughout the forecast period with the bulk of the growth in the Rocky Mountain Subregion. There is also a projected use of coal after 1975 for the production of synthesized oil and gas to fuel thermal power production. Future improvements in the economics of EHV transmission and dry cooling may enhance coal's competitive position and give it an even larger role in the fuel supply mix of the West Region.

Large reserves of coal which can be recovered by low cost stripping methods are available in the West Region for electric generation. Anticipated improvements in mining methods and productivity should tend to stabilize the mine price of coal. Prices are projected to rise only moderately during the latter part of the forecast period.

Nuclear-fueled thermal generating plants, unlike fossil-fueled plants, do not contribute to air pollution. Furthermore, they are not sensitive to fuel transportation costs. Reserves of uranium are thought to be adequate to supply the nuclear fuel demand throughout the forecast period. Cost improvements in the processing and manufacturing steps of the fuel cycle are anticipated to offset the expected increases in the recovery cost of a dwindling supply of raw materials. Breeder reactors, upon which a great deal of research and development work is currently being carried on, will extend the energy generation potential from existing uranium reserves.

Generation

The West Region patterns of generation for 1970, 1980, and 1990 clearly illustrate this region's great variety of energy resources. Between 1970 and 1990 utilities within the region expect to construct every significant type of generation—including nuclear; gas, oil, and coal-fired thermal; geothermal; con-

ventional hydro; hydro pumped storage; and peaking thermal. The separation of load centers by considerable distances is one major reason for the variety of planned generation. Another is that sources of energy supply are not uniformly distributed throughout the region.

Suitable topography and abundant rainfall have made it possible to develop large amounts of hydroelectric power in the Pacific Northwest and the northern part of California. However, future increases in energy supplies for these areas will be largely from thermal resources because most of the economic hydro energy has already been developed. Southern California, the Southwest, Colorado and Utah have depended primarily on fossil fuels for electric generation. Some inland portions of the West Region have available large reserves of coal, oil, and gas as compared to Northern California and the Pacific Northwest. In areas lacking large fossil-fuel supplies the cost to transmit electric energy or transport fossil-fuels will tend to make nuclear power the economic resource for future base-load generation.

Sources of Supply

Nuclear generation is characterized by its relatively high capital cost but low incremental fuel cost, indicating its use for high load factor operation. Generally, nuclear units are expected to be among the largest thermal units because of economies of scale.

The usefulness of hydroelectric generation for peaking purposes and for rapid response following system disturbances will continue to be an important factor in overall generation planning. Hydro plants therefore will continue to be installed wherever adequate sites exist or where units can be added to existing sites.

As more large thermal plants are installed, the same factors which have justified pumped storage plants in the eastern states and some parts of the Rocky Mountains could make pumped storage more attractive at other locations.

Gas turbine peaking units are expected to be located near load centers at sites where gas and oil-fired plants are presently located. They will generally be used for start-up and reserve purposes resulting in very few hours of annual operation. However, they are capable of operating for long periods of time during emergencies, which gives them an advantage over very low capacity factor hydro installations.

To determine the proper mix of base load and peaking resources, utilities in the West are continuously examining their load characteristics and reserve requirements. Where it is economic and suitable, exchanges of hydro peaking power for off-peak thermal energy are being used as a resource.

Present and possible future interchanges of power were considered in projecting the patterns of generation. However, they were limited to amounts considered to be available within the rather broad framework of existing contractual relationships. Utilities recognize that the economics of specific future proposals could dictate other contracts and the substitution of interchange power for construction of projected resources.

Future economics of the various sources of supply will determine the specific types of peaking and base-load generation, and the amount of interchange power that will be included as resources by 1980 and 1990.

Factors Affecting Selection of Sites

Finding suitable sites for thermal units is becoming increasingly difficult and the cost of developing the sites to meet the many restrictions now imposed will have an important impact on the economy of future generation. Environmental considerations such as esthetics, thermal effects, and air quality control have taken on such importance that they often make otherwise acceptable sites unsuitable to develop. Nuclear plants are favored from an air quality control standpoint; however, cooling water requirements for nuclear plants are greater than for fossil-fueled thermal plants.

The best hydro sites in the region have already been at least partially developed; however, more will be developed incidental to irrigation and flood control projects. Pumped storage sites in the region will be developed where the resources mix permits and when pumped storage facilities are the economic alternative.

Reserve Requirements

Reliability of bulk power supply receives much attention by utilities in the West. Resources are planned to provide not only spinning reserves but also to protect against various combinations of forced outages. The large systems in the region make extensive use of high speed computers for studies of system reliability. These studies include the planned maintenance schedules, forced outage

rates and unit sizes of existing and planned resources, and transmission capacity reserved for emergency power transfers.

The amount of reserves planned varies over the region depending on the particular types of generation, resource pooling and other considerations. Large unit sizes relative to the system size require increases in reserve capacity. However, economies of scale and system fuel cost savings have in many cases justified installation of the largest unit size available. In planning generation it is realized that first-of-a-kind units will continue to require more test time prior to commercial operation and substantially more lead time because of the lengthy licensing process and unpredictable construction delays. Shakedown of the more complex generating units requires temporarily increased amounts of reserve capacity until a mature, more reliable performance status is achieved.

Reserve requirements will change with the selection of unit sizes, experience with forced outage rates, number and strength of interconnections, and pooling arrangements.

Utilities have been able to obtain the benefits of coordinated or joint development of large generating units. Projects such as San Onofre, Four Corners, Mohave, and Centralia are excellent examples.

Coordinated planning, now being accelerated, will open opportunities for economic benefits through contracts for economy energy interchange, reserve pooling, overhaul schedule optimizing, and sharing of spinning reserve while maintaining a high level of reliability.

In the appended report on Future Generation Patterns for the West Region are resource tabulations and summary tables of peak loads, resources (classified by type), scheduled overhaul at the time of the peak load, and reserve margins for 1970, 1980, and 1990. Also included are pictorial maps of the West Region showing the pattern of generation for the three target years.

Transmission

Existing Network

Transmission of electric power in the West Region is characterized to a large degree by long distances between hydro or remotely located thermal power sources and load centers. The composite of interconnected systems in the region comprises a large loop referred to as the Western Loop. In 1970 the western side of this loop will include two 500 kv AC lines and a 750 kv DC line making up the western portion of the Northwest-Southwest Intertie (Pacific Intertie) and the south side of the loop will consist of 500 kv and 345 kv lines across Arizona with 500 kv, 287 kv, and 230 kv continuing into Southern California. The eastern and northern sides consist of multiple 230 kv transmission lines through Utah, Colorado, Wyoming, Idaho and Montana into Washington and Oregon.

The Pacific Intertie is a significant step in transmission development in the West Region. The two 500 kv lines of the Intertie supplement the backbone transmission in California and together with the DC line provide interconnection between the major hydro and steam generating areas. This intertie allows several types of peak and energy transfers with resulting benefits to all utilities involved.

The West Region is composed of a number of operating areas which have achieved a high degree of reliable operation. Procedures in these areas for meeting operating contingencies vary. Under severe emergency conditions, both load shedding and opening of interconnections are used to avoid extensive and prolonged disruption of service. Interruption of interconnections varies from automatic relaying under selected conditions to tripping only at such time as there is danger of damage to connected equipment. Studies are proceeding under the direction of the Western Systems Coordinating Council to continue coordination of these various concepts and operating practices and to establish criteria essential to reliable operation of the region's interconnected systems.

Studies have shown that beginning in 1969 substantial "circulating" power flows, i.e., power flows in a direction opposite to that intended not actually circulating, will occur on the Western Loop due to large exports to the east from the mid-Columbia plants in Washington, part of which flows counterclockwise around the Loop rather than over the heavily loaded lines from these plants to the east. This condition will be relieved to some extent in 1972 by transmission capacity increases east of the mid-Columbia including series capacitor additions, the 500 kv Lower Monumental-Dworshak Dam (near Lolo)-Hot Springs lines and addition of two steam generating units in Wyoming.

Future Network

Construction of long distance transmission lines is expected to continue to be required for the de-

livery of bulk power from remote hydro and mine-mouth thermal plants to load centers. A major development in transmission will be 500 kv to integrate large coal-fired thermal plants with load centers in Arizona and Southern California. In instances where generation will supply separate load areas located relatively close together, large capacity tie lines between the load areas will be economically justified. Future transmission plans for some areas are based on locating major thermal plants in or adjacent to load centers, thus reducing the requirement for transmission. These are the areas where nuclear plants are expected to develop. With time, the function of some major transmission systems in these areas originally built to provide bulk transmission will be utilized for reserve capacity, economy exchange, and peaking service.

Future development of Extra High Voltage transmission (EHV) in the West Region will basically be to overlay or parallel existing networks, retaining the transmission loop routed around Nevada. The loop will, however, be considerably strengthened with additional EHV lines. This together with application of advancements in control techniques will result in continuing improvement in the stability and reliability of the interconnected systems.

It is expected that in the future the 500 kv systems will be strengthened in the Northwest, in Southern California and from the Four Corners—Southern Utah area—to Southern California. In the Northwest the principal extension of 500 kv is expected to be into Western Montana. Multiple 345 kv transmission lines will be built to meet needs of Idaho, Montana and Utah. Transmission at 230 kv is anticipated to be adequate to meet the needs of Wyoming and Colorado during the 1970's with the longer range possibility of going directly from 230 kv to 500 kv in these areas. New Mexico and Western Texas requirements are to be met by expansion at 345 kv.

For the 1970 level of transmission development, the amount of interregional tie capacity might be considered to be a part of the natural sequence of transmission growth. This is brought about primarily as a result of growth of adjoining regional networks with only incidental capability of handling interregional power flows. For future development all of the lines above 230 kv between the West Region and the West Central Region are assumed to be required for firm power transfers easterly from the Montana-Wyoming coal fields. If a high capacity interregional network is found to have economic advantages, utilities will respond as in the past under similar circumstances. For example, the Pacific Intertie connecting widely separated areas in the West came about as the result of cooperative efforts on the part of public and privately owned utility systems and agencies of the Federal government. Power transfers and exchanges over this intertie are recognized by the parties involved as being mutually advantageous.

The forecasted transmission network will have sufficient capacity to take advantage of any economic diversities of loads and resources within the region.

Reliability of Systems

It is believed that the transmission systems in the region will continue to provide a high degree of reliability. This will be assured by providing capacity needed to match generation to load requirements, by providing adequate levels of interconnecting capacity between areas and also through use of multiple lines and application of improved and advanced control techniques.

Practices of Conserving Rights-of-Way

Planning is being done by systems in the region that will result in upgrading the capability of transmission lines on existing rights-of-way. There are many examples of line replacements and upgrading that indicate a determined effort to conserve transmission line rights-of-way. New transmission tower designs are being developed that will permit the use of right-of-way widths of 125 to 150 feet for a 500 kv circuit. This development will make possible conversion to higher voltages on existing rights-of-way and in some cases without increasing the width. For voltages above 500 kv required minimum conductor spacings make necessary greater width of right-of-way per circuit; however, fewer circuits are required so that total right-of-way is less than if all added lines are at 500 kv.

Coordinated Planning and Development

Growth of Coordinated Planning

Historically, interconnections between power systems were generally developed on a system by system, line by line basis. However, as the ties between individual systems became ties of a totally integrated network, the interdependence of the utilities' systems became apparent. Utilities recognized that

economic advantages could be obtained if they coordinated their plans for developing generation and transmission. These recognitions led to the formation of several coordinating groups in the West Region. They also recognized that to maintain a reliable bulk power supply required that they should share plans for system development.

Coordinating Groups

All coordinating groups, whether they are called pool, association, committee or council, have one underlying purpose—they all are forums for sharing both experience and ideas on how best to proceed in a joint effort to solve mutual problems of electric systems. Because some of the groups are tailored to solve localized problems and some to solve problems on a regional basis, several separate groups have been formed to meet specific objectives. In 1967, the Western Systems Coordinating Council was organized to include the total interconnected western system.

While membership in the various groups is voluntary, each group usually includes systems that influence reliability and operation of other systems in the group. Most power systems have found it to be in their own best interest to participate. Some of the major purposes for which these several groups exist are:

- Agree on procedures for interchange control.
- Supervise inter-system metering and accounting.
- Coordinate Maintenance.
- Insurance compatible relay settings and communications systems.
- Manage reactive resources and voltage compensation.
- Provide analysis and advice where congressional authorizations are required.
- Coordinate planning and/or operation of power resources.
- Coordinate planning and/or operation of transmission facilities.
- Coordinate river operation between upstream and downstream plants of various ownership.
- Encourage joint construction contracts.
- Encourage contractual capacity and energy transactions including wheeling agreements.
- Set procedures for frequency control and time error corrections.
- Review load growth and new facility construction.
- Coordinate the operation of hydro electric and thermal systems of separate ownership.
- Achieve reliable operation and economic utilization of generating and transmission facilities.
- Recommend operating policies to insure close coordination with regional or total western pools and councils.
- Perform stability studies.
- Perform emergency load reduction studies.
- Recommend spinning reserve requirements.
- Provide for emergency service or standby service.
- Supervise power imports from outside the United States.
- Develop basic guides for interconnected operation.

Certain associations have been formed to accomplish, on a regional basis, parallel functions to those of some of the smaller area "pooling" agreements. Many of these larger coordinating groups are interested not only in integrated regional planning but also in providing economies of scale for their members while protecting the responsibility of individual members to be self-sufficient if necessary.

The Western Systems Coordinating Council is oriented totally towards the bulk power system. Member systems are individually responsible for all planning. However, the Council's Planning Coordination Committee conducts studies to determine the effect of the individual plans upon reliability of the network and makes recommendations based on these studies. Operating procedures relating to reliability are the function of the Operations Committee. Its recommendations for operating policies are provided to guide the member utilities. Since all the council data and computer programs are available for the members to use, a means has been established for every system to know how its plans will affect other systems and how other systems' plans may affect it.

The Future of Coordinated Systems Development

The western coordinating groups will continue to update criteria relating to generation reserves, load shedding practices, relaying, line loading, unit and plant sizes and other elements of power system engineering. Not all these topics are properly the function of any one group. The expected large increase

in electric power requirements will cause even greater emphasis to be placed on reliability, while continuing a concern for the quality of the environment.

Over the long range, WSCC is expected to serve as a vehicle for motivating research and the development of solutions to problems peculiar to the western states. Recent work on criteria for system planning and development of highly sophisticated computer programs will continue to be expanded and refined. The role of computers for operation, in addition to planning, is anticipated for development on a step by step basis. The proper amount and distribution of spinning reserve and its rate of response are important to reliability and will receive continuing investigation. It is necessary to prevent cascading outages following any disturbance and the constant updating of design and operating techniques will provide the means for avoiding such cascading.

While relatively weak east-west ties presently exist, a more comprehensive study will need to be completed before additional east-west ties are made. Higher voltage lines with their higher capacity could be even more disruptive to power systems in the immediate interconnected area than is now the case, if these lines are not carefully integrated into the existing network. Therefore, it is essential that close liaison be maintained between WSCC and coordinating councils such as Mid-Continent Area Power Planners and Southwest Power Pool to assure the necessary reliability of any additional interregional ties that may be investigated.

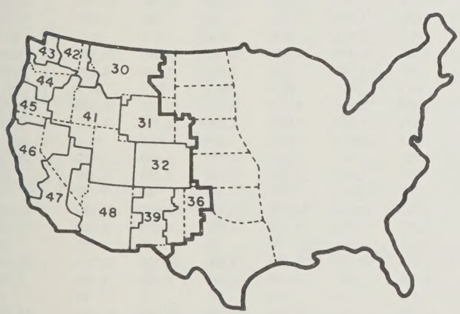
It is expected that the National Electric Reliability Council will be able to assist in the development of interregional reliability. As a forum to exchange information with respect to planning and operating matters, it will also review regional and interregional activities on reliability as well as providing information on such matters to appropriate federal agencies.

APPENDIX 1
FUTURE POWER REQUIREMENTS

Prepared by Subcommittee on Power Requirements and Load Diversity

General

The estimated future power requirements for the West Region were developed from the projected power requirements of the 13 Western Power Supply Areas (PSA) shown on the map below. The boundaries of the PSA's, as established by the Federal Power Commission, are generally determined on the basis of the service areas and operating relationship of the utility systems. The West Region includes the Western States in the contiguous United States west of and including most of Montana and Wyoming, a small portion of southwest South Dakota, the panhandle portion of Nebraska, Colorado, Morton County, Kansas, the panhandle of Oklahoma, New Mexico, and the panhandle and western tip of Texas.



Forecasts of future power needs were developed for PSA's 31, 32, 36, and 39 by the staff of the Fort Worth Regional Office and for PSA's 30 and 41 through 48 by the staff of the San Francisco Regional Office with the assistance and cooperation of a utility task force.

The projected future power requirements for each PSA were based on trends of load growth supplemented by analyses of factors within each PSA, such as projections for population and business indices, increased customer usage (lighting, refrigeration, air conditioning, heating, etc.), cost of electricity, competitive fuels, water project pumping demands, new uses of electric energy, and other specific factors having a bearing on the rate of growth within each PSA. These estimates of the future power needs in the West Region to 1990 were, after review and revisions, approved by the West Region Advisory Committee at its ninth meeting, October 4, 1967. The committee's report, outlining its review of initial estimates, is included here as part of appendix 1.

The present estimate of West Region future power requirements indicates a growth rate greater than that shown in the 1964 National Power Survey. This increased rate of load growth follows a trend similar to that of the total electric energy growth in the contiguous United States. The rate of energy load growth within the individual PSA's in the West Region, however, is expected to vary. In 1965 the energy requirements of the West Region were about 20% of the total for the nation and by 1990 the percentage is not expected to change significantly.

Annual Power Requirements

As indicated in Table 1, the total energy requirements for the West Region in 1965 amounted to 212,550 gwh with a corresponding peak demand of 37,545 mw, and a load factor of 64.6%. For 1990 these are estimated at 1,232,800 gwh, 216,420 mw, and a load factor of 65.0%. This represents an energy growth of 5.8 times and an average compound rate of growth of 7.3% over this 25-year period.

Of all the PSA's in the West Region, the area of southern California and central Nevada, PSA 47, with 51,129 gwh in 1965 had the largest energy requirement. This was 24% of the West Region total energy requirement. In 1990 the energy requirement of PSA 47 is expected to remain at about this same percentage relationship. The Arizona area, PSA 48, is expected to have the highest rate

of growth for the 1965 to 1990 period, an average compound rate of 8.1%.

The past and estimated future annual power requirements (energy, peak demand, and load factor) for the West Region by PSA's are shown on Table 1. The comparative growth of energy requirements is indicated on Table 2.

Figures 1 and 2 indicate the past and estimated future annual power requirements (energy and peak demand) for three typical PSA's—32, 43, and 47 in the West Region. PSA 47 (the southern California-central Nevada area) represents California and the Southwest, the area with the greatest power requirements in the West Region; PSA 43 (Washington) represents the Pacific Northwest; while PSA 32 (Colorado) represents the eastern side of the West Region.

Seasonal Characteristics

Because the West Region's area covers more than one-third of the contiguous United States, including seacoast, mountainous and desert areas, all types of weather and economic conditions are experienced. Thus wide differences in power usage are experienced now and are to be expected in the future. These differences in power requirements result in peak load diversity throughout the region. The recorded and estimated summer and winter peak demands for the West Region, by PSA's, are shown in Table 3.

The 1965 summer peaks occurred in June, July, or August and the winter peaks occurred in December or January. Similarly, future summer peaks may occur in any of the summer months while the

TABLE 1

WEST REGION

Past and Estimated Future Annual Power Requirements by Power Supply Areas and West Region

Area	Item	Unit	1950	1955	1960	1965	1970	1975	1980	1985	1990
PSA 31	Energy for Load	Gwh	593	1,010	1,854	2,853	4,253	6,370	9,390	13,400	18,800
	Peak Demand	Mw	122	204	328	474	715	1,070	1,570	2,250	3,150
	Load Factor	%	55.5	56.5	64.3	68.7	68.0	67.9	68.3	68.0	68.1
PSA 32	Energy for Load	Gwh	1,980	3,516	5,483	7,790	11,500	16,500	23,400	32,700	45,300
	Peak Demand	Mw	411	683	1,054	1,497	2,130	3,020	4,230	5,860	8,030
	Load Factor	%	55.0	58.8	59.2	59.4	61.6	62.4	63.1	63.7	64.4
PSA 36	Energy for Load	Gwh	1,486	2,828	4,395	6,452	9,170	13,000	18,200	25,100	33,800
	Peak Demand	Mw	287	558	861	1,238	1,790	2,510	3,480	4,770	6,380
	Load Factor	%	59.1	57.9	58.1	59.5	58.5	59.1	59.7	60.1	60.5
PSA 39	Energy for Load	Gwh	750	1,389	2,596	3,664	5,426	7,980	11,500	16,100	21,600
	Peak Demand	Mw	154	266	472	687	1,035	1,520	2,180	3,060	4,090
	Load Factor	%	55.6	59.6	62.6	60.9	59.8	59.9	60.2	60.1	60.3
PSA 30	Energy for Load	Gwh	2,668	4,114	5,004	6,630	8,830	11,740	15,680	21,070	28,390
	Peak Demand	Mw	424	752	775	1,089	1,460	1,940	2,590	3,490	4,700
	Load Factor	%	71.8	62.5	73.7	69.5	69	69	69	69	69
PSA 41	Energy for Load	Gwh	3,056	5,440	8,325	11,119	15,680	22,210	31,420	44,510	63,210
	Peak Demand	Mw	604	949	1,447	2,044	2,840	4,020	5,690	8,060	11,460
	Load Factor	%	57.8	65.4	65.7	62.1	63	63	63	63	63
PSA 42	Energy for Load	Gwh	5,152	8,072	7,798	10,871	13,400	15,800	18,100	20,700	23,000
	Peak Demand	Mw	763	1,181	1,319	1,562	2,190	2,580	2,950	3,380	3,750
	Load Factor	%	77.1	78.0	67.3	79.4	70	70	70	70	70
PSA 43	Energy for Load	Gwh	6,675	12,147	14,456	20,412	30,300	43,500	61,900	86,000	118,700
	Peak Demand	Mw	1,373	2,342	2,663	4,048	5,760	8,280	11,780	16,360	22,580
	Load Factor	%	55.5	59.2	61.8	57.6	60	60	60	60	60
PSA 44-45	Energy for Load	Gwh	11,827	17,899	25,472	33,522	49,700	69,800	96,800	133,300	183,000
	Peak Demand	Mw	2,023	3,286	4,311	6,013	8,930	12,550	17,400	23,960	32,900
	Load Factor	%	66.7	62.2	67.3	63.6	63.5	63.5	63.5	63.5	63.5
PSA 46	Energy for Load	Gwh	13,967	20,769	30,099	42,654	63,400	92,900	136,000	199,000	291,000
	Peak Demand	Mw	2,500	3,761	5,525	7,639	11,200	16,500	24,100	35,300	51,600
	Load Factor	%	63.8	63.0	62.2	63.7	64.6	64.3	64.4	64.4	64.4
PSA 47	Energy for Load	Gwh	14,202	22,148	33,682	51,129	72,500	106,000	151,000	213,000	298,000
	Peak Demand	Mw	2,759	4,312	6,267	9,451	13,300	19,400	27,700	39,200	55,000
	Load Factor	%	58.8	58.6	61.3	61.8	62.3	62.4	62.2	62.0	61.9
PSA 48	Energy for Load	Gwh	2,869	6,082	10,572	15,452	23,600	34,400	50,300	73,800	108,000
	Peak Demand	Mw	561	1,166	2,022	2,941	4,490	6,550	9,570	14,000	20,600
	Load Factor	%	58.4	59.5	59.7	60.0	60	60	60	60	60
WEST Region	Energy for Load	Gwh	65,225	105,414	149,736	212,548	307,759	440,200	623,690	878,680	1,232,800
	Peak Demand [1]	Mw	11,981	19,460	27,044	37,545	54,035	77,28C	109,420	154,250	216,420
	Load Factor	%	62.1	61.8	63.0	64.6	65.0	65.0	65.1	65.0	65.0

[1] 1950–1960: non-coincident; 1965–1990: coincident.

30,000 Hydro 351
40,000 [illegible]

future winter peaks may be expected to occur in December or January.

In the Pacific Northwest, PSA's 42–45 peak in the winter while PSA 41 peaks in the summer, primarily due to irrigation pumping loads and air conditioning. Utilities in these PSA's have for many years taken advantage of this diversity in constructing their generating capacity needs. Load diversity may exist within a single PSA or even within the area of a single utility. PSA 46, where agricultural pumping and air conditioning loads create summer peak loads nearly identical with the winter peaks, is an example of this. This internal diversity is advantageous to the particular area in planning its generation requirements and decreases, or may eliminate, the potential for sharing diversity with other areas.

The past and estimated future monthly peak requirements for 10-year intervals to 1990 are shown on Table 4 for the 13 PSA's and for the total West Region. Table 5 shows the monthly energy requirements over this same period. The ratio of recorded minimum monthly peaks to annual peak for the total West Region amounted to 89% in 1960 and is estimated to be 87% in 1990 with December continuing to be the peak month (calendar year basis).

TABLE 2

WEST REGION

Comparative Growth of Total Energy Requirements by Power Supply Areas and West Region

[Index: 1960=100]

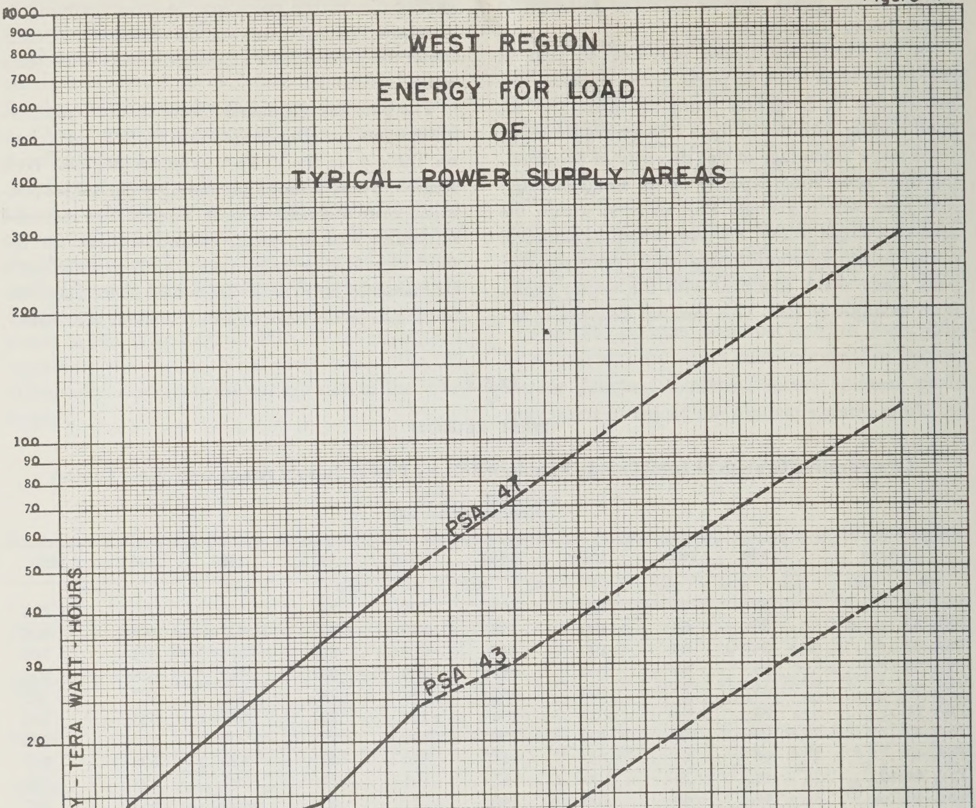
Area	1950	1955	1960	1965	1970	1975	1980	1985	1990
PSA 31	32	54	100	154	229	344	506	723	1,014
PSA 32	36	64	100	142	210	301	427	596	826
PSA 36	34	64	100	147	209	296	414	571	769
PSA 39	29	54	100	141	209	307	443	620	832
PSA 30	53	82	100	132	176	235	313	421	567
PSA 41	37	65	100	134	188	267	377	535	759
PSA 42	66	104	100	139	172	203	232	265	295
PSA 43	46	84	100	141	210	301	428	595	821
PSA 44–45	46	70	100	132	195	274	380	523	718
PSA 46	46	69	100	142	211	309	452	661	967
PSA 47	42	66	100	152	215	315	448	632	885
PSA 48	27	58	100	146	223	325	476	698	1,022
WEST Region	44	70	100	142	206	294	417	587	823

Five Year Compound Rate of Energy Growth

[In percent]

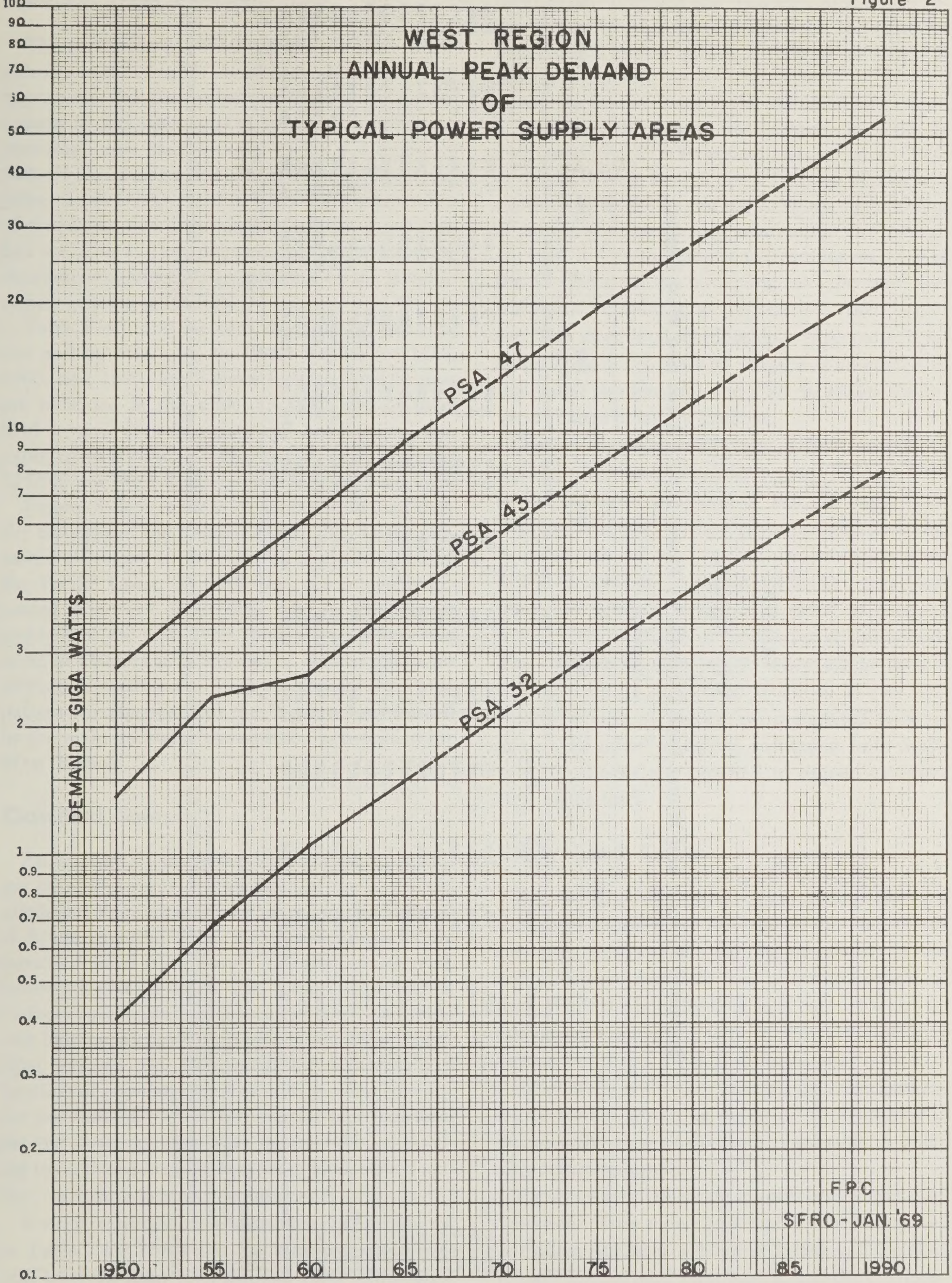
Area	1950–1955	1955–1960	1960–1965	1965–1970	1970–1975	1975–1980	1980–1985	1985–1990
PSA 31	11.2	12.9	9.0	8.3	8.4	8.1	7.4	7.0
PSA 32	12.2	9.3	7.3	8.1	7.5	7.2	6.9	6.7
PSA 36	13.7	9.2	8.0	7.3	7.2	7.0	6.6	5.1
PSA 39	13.1	13.3	7.1	8.2	8.0	7.6	7.0	6.0
PSA 30	9.0	4.0	5.8	5.9	5.9	5.9	6.1	6.1
PSA 41	12.2	8.9	5.9	7.1	7.2	7.2	7.2	7.3
PSA 42	9.4	–0.7	6.9	4.3	3.3	2.8	2.7	2.1
PSA 43	12.7	3.5	7.1	8.2	7.5	7.3	6.8	6.7
PSA 44–45	8.6	7.3	5.6	8.2	7.0	6.8	6.6	6.5
PSA 46	8.3	7.7	7.2	8.2	7.9	7.9	7.9	7.9
PSA 47	9.3	8.7	8.7	7.2	7.9	7.3	7.1	6.9
PSA 48	16.4	11.7	7.9	8.8	7.8	7.9	8.0	7.9
WEST Region	10.1	7.3	7.3	7.7	7.4	7.2	7.1	7.0

Figure I



WEST REGION
ENERGY FOR LOAD
OF
TYPICAL POWER SUPPLY AREAS
ENERGY - TERA WATT - HOURS
PSA 47
PSA 43
PSA 32
1000
900
800
700
600
500
400
300
200
100
90
80
70
60
50
40
30
20
10
9
8
7
6
5
4
3
2
1
1950
55
60
65
70
75
80
85
1990
FPC
SFRO-JAN. '69

Figure 2


WEST REGION
ANNUAL PEAK DEMAND
OF
TYPICAL POWER SUPPLY AREAS
PSA 47
PSA 43
PSA 32
DEMAND - GIGA WATTS
100
90
80
70
60
50
40
30
20
10
9
8
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6
5
4
3
2
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0.9
0.8
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0.5
0.4
0.3
0.2
0.1
1950
55
60
65
70
75
80
85
1990
FPC
SFRO - JAN. '69

TABLE 3

WEST REGION

Estimated Summer and Winter Peak Demands by Power Supply Areas and West Region

[Megawatts]

Area	1965				1970		1975		1980		1985		1990	
	Summer		Winter		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
	Month	Peak	Month	Peak										
PSA 31	Aug.	456	Dec.	*474*	660	*715*	995	*1,070*	1,460	*1,570*	2,093	*2,250*	2,930	*3,150*
PSA 32	Aug.	1,314	Dec.	*1,497*	1,940	*2,130*	2,750	*3,020*	3,850	*4,230*	5,330	*5,860*	7,310	*8,030*
PSA 36	Jul.	*1,238*	Dec.	1,034	*1,790*	1,490	*2,510*	2,080	*3,480*	2,890	*4,770*	3,960	*6,380*	5,300
PSA 39	Jul.	*687*	Dec.	670	*1,035*	1,000	*1,520*	1,470	*2,180*	2,110	*3,060*	2,970	*4,090*	3,970
PSA 30	Aug.	964	Dec.	*1,089*	1,260	*1,460*	1,680	*1,940*	2,240	*2,590*	3,020	*3,490*	4,070	*4,700*
PSA 41	Jul	*2,044*	Dec.	1,825	*2,840*	2,440	*4,020*	3,450	*5,690*	4,890	*8,060*	6,920	*11,460*	9,840
PSA 42	Jun.	1,465	Jan.	*1,613*	2,120	*2,470*	2,500	*2,920*	2,860	*3,330*	3,280	*3,820*	3,640	*4,240*
PSA 43	Jun.	2,908	Dec.	*4,048*	4,320	*5,970*	6,210	*8,580*	8,840	*12,200*	12,300	*16,900*	16,900	*23,400*
PSA 44–45	Jun.	4,587	Dec.	*6,013*	7,050	*9,470*	9,910	*13,300*	13,800	*18,400*	18,900	*25,400*	26,000	*34,900*
PSA 46	Aug.	7,383	Dec.	*7,639*	*11,200*	11,100	*16,500*	16,300	*24,100*	23,800	*35,300*	34,900	*51,600*	51,000
PSA 47	Aug.	8,957	Dec.	*9,451*	12,700	*13,300*	18,500	*19,400*	26,500	*27,700*	37,400	*39,200*	52,500	*55,000*
PSA 48	Aug.	*2,941*	Jan.	2,277	*4,490*	3,520	*6,550*	5,140	*9,570*	7,510	*14,000*	11,000	*20,600*	16,200
WEST Region	Aug.	34,567	Dec.	*37,545*	51,180	*54,035*	73,310	*77,280*	104,120	*109,420*	146,950	*154,250*	206,680	*216,420*

NOTES:

Annual peak demands are *italicized*.

1965 summer and winter peaks occurred in the months indicated.

Future summer peaks may occur in any of the summer months; future winter peaks are estimated to occur in December, except for PSA's 42, 43, and 44–45 whose peaks are estimated to occur in January of the following year.

Principal Load Centers

The tremendous growth of the electric power industry in the decades ahead presents a continuing opportunity for the industry to expand the power systems to take advantage of potential economies in planning future electric power facilities. Familiarity with the distribution and concentration of loads and power needs is important in system planning studies of generation and transmission facilities. Load centers are generally key points on backbone transmission networks and have an influence on the location of new generating facilities.

Table 6 indicates the peak demands by load centers and by PSA's for the West Region for 1970, 1980, and 1990. Forty-seven separate load centers are indicated in this table. In 1990, two of these load centers—San Francisco and Los Angeles—are expected to account for 61,100 mw, or 27% of the 224,240 mw West Region non-coincident total load.

Figure 3 depicts the wide variation in load density throughout the Region. About 70% of the estimated 1970 load is concentrated in the areas along the Pacific Coast. In 1990 this percentage is expected to increase about 72%. Also, by 1990 almost one-half of the total West Region load is expected to be in California. The areas of heavier load concentration encircle the State of Nevada. This load pattern corresponds with the Western loop formed by the main backbone transmission networks in the West Region.

Classified Sales

An analysis of projected load growth by major use categories gives an indication of the individual area's and Region's economy as well as the direction of future growth. These major use categories are broadly defined as rural and residential, commercial, industrial, and all other. The "other" classification includes such miscellaneous uses as street and highway lighting, electrified transportation, other municipal services, etc. Residential use is normally a function of population and steadily growing average use per customer while commercial and industrial use per customer may vary considerably, depending upon the wide range in types of loads served and their variations in power requirements.

Energy requirements by class of service are shown in Table 7 for PSA's and the West Region at five-year intervals from 1965 through 1990. Although it is difficult to predict with assurance the development of new products and their estimated power requirements in long-range projections, the effect of new uses of electric power is reflected throughout these projections.

As indicated in Table 7, the industrial load classification was the largest use category in 1965. It accounted for 72,600 gigawatt-hours (over 34% of the total West Region use). Through 1990 it will continue to be the largest use category, maintaining about the same percentage relationship to the total. In 1965 it was the largest use component in 9 of the 13 PSA's. In the remaining four the rural and residential classification represented the largest use. This same total relationship is expected to exist in 1990; however, PSA 46 changes from rural and residential to industrial and PSA 48 makes the reverse change in largest load use.

The percentage distribution of total energy for load by major use catgeories for the 1965 to 1990 period is shown in Table 8. For the total West Region, the industrial class indicates a slight increase in percentage of total energy use, changing from 34.2% in 1965 to 34.5% in 1990. The rural and residential class of service is expected to decrease from 30.3% to 28.2% of the total over this period. The commercial class is also estimated to decline in its percentage share from 20.3% to 18.9%. The greatest gain in percentage use is expected to occur in the "all other" category, increasing from 5.4% to 8.3%. Losses are expected to remain at about 10% of the load.

Utility Load Curves

An electric utility's load curve, a chart showing the power supplied plotted against the time of occurrence, illustrates the varying magnitude of the utility's power demands over a certain period of time. While the hour-by-hour load curves for individual power systems may have considerable similarity in time and shape, the peak demands may not occur coincidentally with other systems. Detailed load-resource studies would be necessary to determine if this diversity in peak demands is valuable in planning future resources.

Figures 4 and 5 illustrate summer and winter load conditions. They show the actual hourly load curves of Friday, August 6, 1965, and Tuesday, December 7, 1965, for the total West Region and the previously referred-to-typical PSA's 32, 43, and 47.

TABLE 4

WEST REGION

Past and Estimated Future Monthly Peak Demands

[Megawatts]

	January	February	March	April	May	June	July	August	September	October	November	December
1960												
PSA 31	289	275	268	251	247	274	295	304	303	299	314	328
PSA 32	945	895	882	832	839	912	975	981	965	946	1,024	1,054
PSA 36	577	573	616	669	688	735	789	861	733	669	715	717
PSA 39	404	400	392	398	406	461	472	467	465	426	439	459
PSA 30	703	721	739	713	716	703	722	695	690	718	722	775
PSA 41	1,239	1,201	1,201	1,217	1,344	1,447	1,440	1,418	1,369	1,233	1,297	1,316
PSA 42	1,319	1,255	1,300	1,250	1,231	1,289	1,163	1,132	984	1,019	1,140	1,225
PSA 43	2,663	2,472	2,566	2,241	2,195	2,057	1,943	2,088	2,126	2,364	2,648	2,642
PSA 44-45	4,311	4,109	4,259	3,730	3,768	3,406	3,435	3,617	3,693	3,826	4,221	4,258
PSA 46	4,829	4,543	4,649	4,580	4,735	5,370	5,525	5,320	4,958	4,846	4,906	5,043
PSA 47	5,725	5,656	5,540	5,587	5,398	5,637	5,927	5,829	6,257	6,166	5,890	6,267
PSA 48	1,300	1,259	1,515	1,531	1,706	1,969	2,010	2,003	2,022	1,640	1,508	1,614
WEST Region	24,304	23,359	23,927	22,999	23,273	24,260	24,696	24,715	24,565	24,152	24,824	25,698
1970												
PSA 31	640	620	590	590	590	620	640	660	620	640	670	715
PSA 32	1,920	1,830	1,790	1,750	1,750	1,830	1,940	1,920	1,850	1,870	2,040	2,130
PSA 36	1,270	1,200	1,340	1,400	1,410	1,470	1,740	1,790	1,500	1,320	1,450	1,490
PSA 39	910	880	870	870	920	990	1,035	1,010	980	950	960	1,000
PSA 30	1,390	1,310	1,270	1,230	1,240	1,200	1,230	1,260	1,260	1,290	1,390	1,460
PSA 41	2,410	2,270	2,140	2,120	2,400	2,670	2,840	2,780	2,530	2,360	2,410	2,440
PSA 42	2,090	2,000	1,960	1,980	2,080	2,120	2,010	2,040	1,970	1,960	2,040	2,190
PFS 43	5,470	5,010	4,900	4,800	4,440	4,200	4,150	4,320	4,380	4,950	5,300	5,760
PSA 44-45	8,570	8,040	7,650	7,410	7,230	6,970	6,790	7,050	7,140	7,590	8,300	8,930
PSA 46	10,100	9,810	9,800	9,700	9,980	11,000	11,000	11,200	10,200	10,000	10,400	11,100
PSA 47	11,800	11,600	11,600	11,600	11,100	11,700	12,400	12,700	12,600	12,600	12,800	13,300
PSA 48	3,260	3,230	3,440	3,480	3,860	4,230	4,490	4,450	4,180	3,710	3,310	3,520
WEST Region	49,830	47,800	47,350	46,930	47,000	49,000	50,265	51,180	49,210	49,240	51,070	54,035

1980												
PSA 31	1,410	1,370	1,300	1,290	1,290	1,350	1,410	1,440	1,350	1,400	1,480	1,570
PSA 32	3,810	3,640	3,550	3,380	3,470	3,640	3,850	3,810	3,680	3,720	4,060	4,230
PSA 36	2,440	2,330	2,610	2,710	2,750	2,850	3,380	3,480	2,920	2,580	2,820	2,890
PSA 39	1,920	1,850	1,830	1,830	1,940	2,090	2,180	2,140	2,070	2,010	2,030	2,110
PSA 30	2,460	2,330	2,260	2,180	2,190	2,140	2,190	2,240	2,230	2,290	2,460	2,590
PSA 41	4,840	4,550	4,280	4,240	4,810	5,350	5,690	5,560	5,060	4,720	4,840	4,890
PSA 42	2,820	2,700	2,640	2,670	2,800	2,860	2,710	2,740	2,650	2,650	2,750	2,950
PSA 43	11,200	10,200	10,000	9,780	9,070	8,600	8,480	8,840	8,950	10,100	10,800	11,780
PSA 44-45	16,700	15,700	14,900	14,400	14,100	13,600	13,200	13,800	13,900	14,800	16,200	17,400
PSA 46	21,800	21,100	21,100	20,900	21,500	23,600	23,700	24,100	21,900	21,500	22,400	23,800
PSA 47	24,700	24,100	24,100	24,200	23,000	24,400	25,800	26,500	26,300	26,100	26,600	27,700
PSA 48	6,960	6,880	7,330	7,410	8,230	9,020	9,570	9,470	8,900	7,900	7,060	7,510
WEST Region	101,060	96,750	95,900	94,990	95,150	99,500	102,160	104,120	99,910	99,770	103,500	109,420
1990												
PSA 31	2,840	2,740	2,610	2,580	2,580	2,710	2,840	2,900	2,710	2,800	2,960	3,150
PSA 32	7,230	6,910	6,750	6,420	6,580	6,910	7,310	7,230	6,990	7,070	7,710	8,030
PSA 36	4,470	4,270	4,790	4,980	5,040	5,230	6,190	6,380	5,360	4,720	5,170	5,300
PSA 39	3,600	3,480	3,440	3,440	3,640	3,930	4,090	4,010	3,890	3,760	3,800	3,970
PSA 30	4,470	4,230	4,100	3,960	3,980	3,880	3,970	4,070	4,040	4,150	4,470	4,700
PSA 41	9,740	9,170	8,620	8,540	9,700	10,800	11,460	11,200	10,200	9,510	9,740	9,840
PSA 42	3,590	3,430	3,360	3,390	3,560	3,640	3,450	3,490	3,370	3,360	3,500	3,750
PSA 43	21,500	19,600	19,200	18,700	17,400	16,500	16,300	16,900	17,200	19,400	20,800	22,580
PSA 44-45	31,600	29,600	28,200	27,300	26,600	25,700	25,000	26,000	26,300	28,000	30,600	32,900
PSA 46	46,600	45,200	45,200	44,700	46,000	50,500	50,800	51,600	47,000	46,100	48,000	51,000
PSA 47	49,000	47,900	47,800	48,000	45,800	48,400	51,200	52,500	52,300	51,900	52,900	55,000
PSA 48	15,000	14,800	15,800	15,900	17,700	19,400	20,600	20,400	19,200	17,000	15,200	16,200
WEST Region	199,640	191,330	189,870	187,910	188,580	197,600	203,210	206,680	198,560	197,770	204,850	216,420

TABLE 5

WEST REGION

Past and Estimated Future Monthly Energy Requirements

[Gigawatt-hours]

	January	February	March	April	May	June	July	August	September	October	November	December	Year
1960													
PSA 31	156	138	146	135	147	145	170	172	154	161	156	174	1,854
PSA 32	457	427	442	410	427	437	485	516	463	465	459	495	5,483
PSA 36	327	308	348	367	376	362	383	461	371	349	376	367	4,395
PSA 39	203	191	202	196	211	231	239	251	224	213	209	226	2,596
PSA 30	384	377	444	426	447	416	429	415	369	410	422	465	5,004
PSA 41	656	588	646	642	741	792	816	798	705	631	630	680	8,325
PSA 42	731	625	663	603	633	579	685	684	661	663	619	652	7,798
PSA 43	1,378	1,245	1,313	1,172	1,190	1,055	1,036	1,105	1,085	1,199	1,281	1,397	14,456
PSA 44–45	2,374	2,138	2,263	2,079	2,207	1,932	1,967	2,022	1,892	2,039	2,167	2,392	25,472
PSA 46	2,550	2,169	2,463	2,343	2,451	2,791	2,929	2,873	2,448	2,418	2,269	2,395	30,099
PSA 47	2,732	2,547	2,770	2,653	2,705	2,840	2,996	3,026	2,921	2,870	2,729	2,893	33,682
PSA 48	696	641	794	795	865	1,061	1,164	1,166	1,049	816	753	772	10,572
WEST Region	12,644	11,394	12,494	11,821	12,400	12,641	13,299	13,489	12,342	12,234	12,070	12,908	149,736
1970													
PSA 31	361	323	349	327	340	336	379	379	357	349	361	392	4,253
PSA 32	977	874	931	874	920	932	1,023	1,035	943	978	978	1,035	11,500
PSA 36	687	633	743	761	743	752	908	926	752	734	752	779	9,170
PSA 39	434	386	424	413	451	477	509	509	456	451	445	471	5,426
PSA 30	753	695	754	705	726	705	723	736	714	745	750	824	8,830
PSA 41	1,220	1,110	1,190	1,160	1,330	1,390	1,650	1,560	1,310	1,290	1,190	1,280	15,680
PSA 42	1,150	990	1,100	1,020	1,210	1,160	1,170	1,180	1,040	1,070	1,100	1,210	13,400
PSA 43	2,870	2,550	2,700	2,460	2,410	2,290	2,220	2,300	2,330	2,570	2,560	3,040	30,300
PSA 44–45	4,600	4,130	4,320	3,970	4,020	3,790	3,760	3,890	3,940	4,110	4,320	4,850	49,700
PSA 46	4,910	4,640	5,250	5,000	5,330	5,500	5,920	6,000	5,210	5,220	5,040	5,380	63,400
PSA 47	5,900	5,380	5,950	5,720	5,850	5,920	6,340	6,630	6,070	6,280	6,000	6,460	72,500
PSA 48	1,720	1,580	1,860	1,770	1,990	2,160	2,520	2,500	2,120	1,830	1,720	1,830	23,600
WEST Region	25,582	23,291	25,571	24,180	25,320	25,412	27,122	27,645	25,242	25,627	25,216	27,551	307,759

1980													
PSA 31	798	714	770	723	751	742	836	836	770	789	798	863	9, 390
PSA 32	1, 989	1, 779	1, 895	1, 778	1, 872	1, 895	2, 083	2, 106	1, 919	1, 989	1, 989	2, 106	23, 400
PSA 36	1, 365	1, 256	1, 474	1, 511	1, 474	1, 492	1, 803	1, 838	1, 492	1, 456	1, 492	1, 547	18, 200
PSA 39	920	816	897	874	955	1, 012	1, 081	1, 081	966	955	943	1, 000	11, 500
PSA 30	1, 340	1, 230	1, 340	1, 250	1, 290	1, 250	1, 280	1, 310	1, 270	1, 320	1, 330	1, 470	15, 680
PSA 41	2, 440	2, 230	2, 390	2, 320	2, 660	2, 780	3, 300	3, 140	2, 630	2, 580	2, 380	2, 570	31, 420
PSA 42	1, 550	1, 340	1, 490	1, 380	1, 630	1, 560	1, 570	1, 590	1, 410	1, 440	1, 480	1, 660	18, 100
PSA 43	5, 870	5, 210	5, 530	5, 020	4, 930	4, 670	4, 540	4, 690	4, 760	5, 260	5, 220	6, 200	61, 900
PSA 44-45	8, 960	8, 040	8, 410	7, 740	7, 830	7, 380	7, 330	7, 590	7, 680	8, 010	8, 420	9, 410	96, 800
PSA 46	10, 500	10, 000	11, 300	10, 700	11, 400	11, 800	12, 700	12, 900	11, 200	11, 200	10, 800	11, 500	136, 000
PSA 47	12, 300	11, 200	12, 400	11, 900	12, 200	12, 300	13, 200	13, 800	12, 700	13, 100	12, 500	13, 400	151, 000
PSA 48	3, 660	3, 370	3, 960	3, 770	4, 240	4, 610	5, 370	5, 330	4, 530	3, 910	3, 660	3, 890	50, 300
WEST Region	51, 692	47, 185	51, 856	48, 966	51, 232	51, 491	55, 093	56, 211	51, 327	52, 009	51, 012	55, 616	623, 690
1990													
PSA 31	1, 598	1, 429	1, 542	1, 448	1, 504	1, 485	1, 673	1, 673	1, 542	1, 579	1, 598	1, 729	18, 800
PSA 32	3, 850	3, 443	3, 669	3, 443	3, 624	3, 669	4, 032	4, 077	3, 715	3, 851	3, 850	4, 077	45, 300
PSA 36	2, 535	2, 332	2, 738	2, 805	2, 738	2, 772	3, 346	3, 414	2, 772	2, 704	2, 772	2, 872	33, 800
PSA 39	1, 728	1, 534	1, 685	1, 642	1, 793	1, 901	2, 030	2, 030	1, 814	1, 793	1, 771	1, 879	21, 600
PSA 30	2, 420	2, 230	2, 430	2, 270	2, 330	2, 270	2, 330	2, 370	2, 300	2, 390	2, 410	2, 640	28, 390
PSA 41	4, 920	4, 490	4, 810	4, 680	5, 360	5, 600	6, 610	6, 310	5, 300	5, 180	4, 780	5, 170	63, 210
PSA 42	1, 970	1, 700	1, 890	1, 760	2, 070	1, 990	2, 000	2, 020	1, 790	1, 840	1, 890	2, 080	23, 000
PSA 43	11, 200	10, 000	10, 600	9, 630	9, 460	8, 970	8, 710	9, 000	9, 130	10, 100	10, 000	11, 900	118, 700
PSA 44-45	16, 900	15, 200	15, 900	14, 600	14, 800	14, 000	13, 900	14, 300	14, 500	15, 100	15, 900	17, 900	183, 000
PSA 46	22, 600	21, 300	24, 100	22, 900	24, 500	25, 300	27, 100	27, 500	23, 900	24, 000	23, 100	24, 700	291, 000
PSA 47	24, 300	22, 100	24, 400	23, 500	24, 100	24, 300	26, 100	27, 300	25, 000	25, 800	24, 600	26, 500	298, 000
PSA 48	7, 860	7, 250	8, 500	8, 100	9, 100	9, 890	11, 500	11, 500	9, 710	8, 390	7, 850	8, 350	108, 000
WEST Region	101, 881	93, 008	102, 264	96, 778	101, 379	102, 147	109, 331	111, 494	101, 473	102, 727	100, 521	109, 797	1, 232, 800

TABLE 6

West Region—Peak Demands by Load Centers

Power supply area	Load center	Peak demand—megawatts		
		1970	1980	1990
31	Casper	249	546	1, 100
	Cheyenne	172	378	756
	Scottsbluff	121	265	531
	Cody	115	253	507
	Unassigned	58	128	256
	Total	715	1, 570	3, 150
32	Denver	1, 360	2, 700	5, 130
	Colorado Springs	423	839	1, 590
	Montrose Grand Junction	223	444	842
	Poncha	106	211	400
	Unassigned	18	36	68
	Total	2, 130	4, 230	8, 030
36	Amarillo	632	1, 230	2, 250
	Lubbock	685	1, 330	2, 440
	Hobbs	389	756	1, 390
	Unassigned	84	164	300
	Total	1, 790	3, 480	6, 380
39	Albuquerque	496	1, 040	1, 960
	El Paso	539	1, 140	2, 130
	Unassigned			
	Total	1, 035	2, 180	4, 090
30	Butte-Anaconda	700	1, 240	2, 260
	Billings	175	312	563
	Helena-Great Falls	330	587	1, 060
	Kalispell-Missoula	220	390	707
	Unassigned	35	61	110
	Total	1, 460	2, 590	4, 700
41	Boise	540	1, 080	2, 180
	Pocatello	1, 250	2, 510	5, 050
	Salt Lake City	880	1, 760	3, 540
	Cedar City	86	172	350
	Unassigned	84	168	340
	Total	2, 840	5, 690	11, 460
42	Spokane	1, 740	2, 340	2, 980
	Cour d'Alene	220	300	380
	Lewiston	230	310	390
	Unassigned			
	Total	2, 190	2, 950	3, 750

TABLE 6—Continued

Power supply area	Load center	Peak demand—megawatts		
		1970	1980	1990
43	Seattle-Tacoma	3, 440	7, 040	13, 500
	Bellingham	386	789	1, 520
	Olympia	444	907	1, 740
	Chelan	1, 400	2, 860	5, 470
	Unassigned	90	184	350
	Total	5, 760	11, 780	22, 580
44–45	Portland	5, 350	10, 400	19, 700
	Eugene	1, 450	2, 840	5, 360
	Roseburg-Medford	1, 330	2, 590	4, 880
	Pasco	625	1, 230	2, 310
	Unassigned	175	340	650
	Total	8, 930	17, 400	32, 900
46	San Francisco	5, 060	10, 900	23, 300
	Sacramento	2, 370	5, 090	10, 900
	Fresno	1, 970	4, 230	9, 060
	Reno	320	690	1, 480
	Red Bluff	815	1, 760	3, 780
	Unassigned	665	1, 430	3, 080
	Total	11, 200	24, 100	51, 600
47	Los Angeles	9, 150	19, 100	37, 800
	San Diego	1, 210	2, 520	5, 020
	San Bernardino	1, 704	3, 600	7, 200
	Ventura	530	1, 100	2, 200
	Tulare	365	750	1, 510
	Brawley	155	320	640
	Unassigned	150	310	630
	Total	13, 300	27, 700	55, 000
48	Phoenix	2, 000	4, 260	9, 180
	Tucson	668	1, 420	3, 060
	Yuma	908	1, 940	4, 160
	Las Vegas	688	1, 470	3, 160
	Unassigned	226	480	1, 040
	Total	4, 490	9, 570	20, 600
WEST Region		55, 840	113, 240	224, 240

NOTE: Total peak demands for Power Supply Areas & Region are non-coincident.

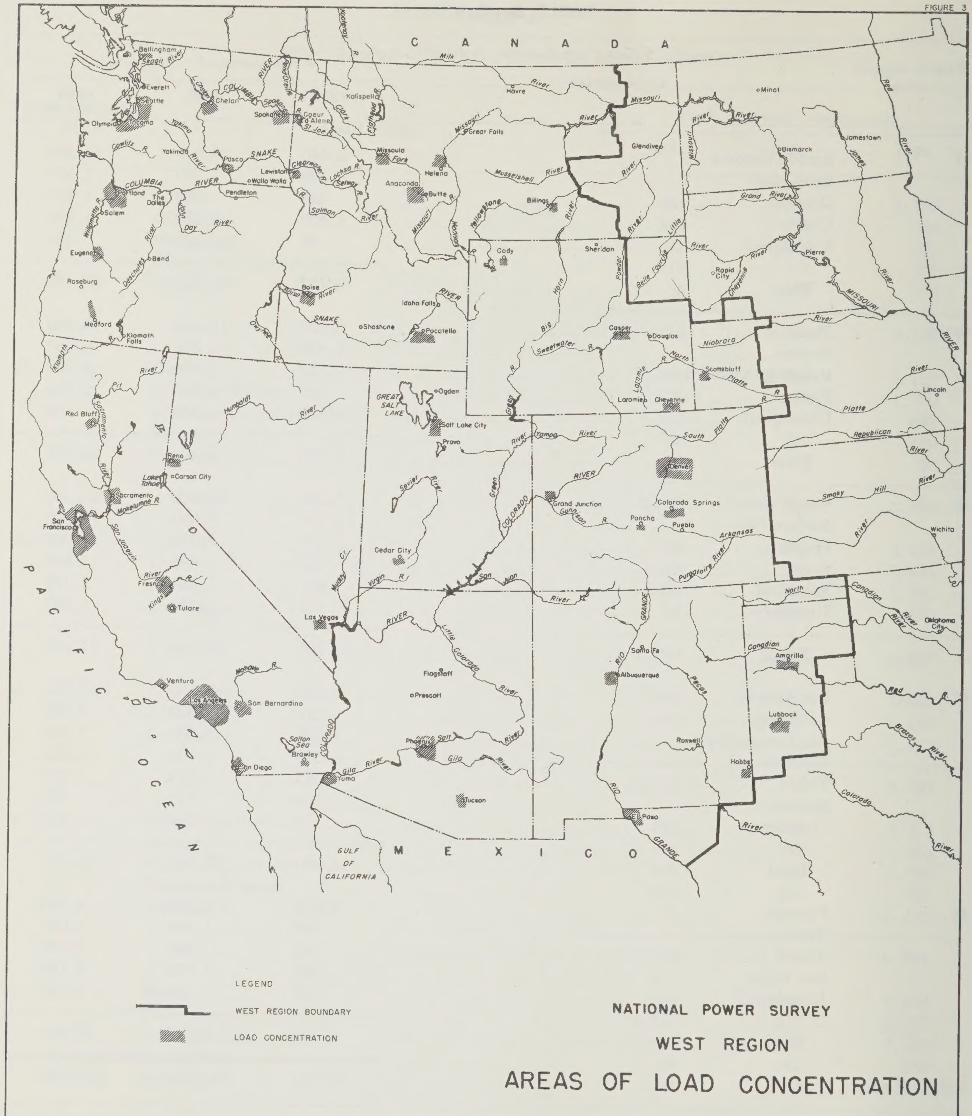


FIGURE 3
CANADA
MEXICO
PACIFIC OCEAN
GULF OF CALIFORNIA
LEGEND
WEST REGION BOUNDARY
LOAD CONCENTRATION
NATIONAL POWER SURVEY
WEST REGION
AREAS OF LOAD CONCENTRATION
SCALE IN MILES
0 50 100 150 200

TABLE 7

West Region—Past and Estimated Future Energy Requirements by Class of Service

[Gigawatt-hours]

Area	Rural and residential	Commercial	Industrial	Street and highway lighting	Electrified transportation	All other	Total to ultimate consumers	Losses	Total energy for load
1965									
PSA 31	624	398	1, 306	31	....	121	2, 480	373	2, 853
PSA 32	2, 520	2, 449	1, 785	99	....	270	7, 123	667	7, 790
PSA 36	1, 713	1, 286	2, 473	55	....	215	5, 742	710	6, 452
PSA 39	1, 035	1, 017	797	43	1	474	3, 367	297	3, 664
PSA 30	1, 076	670	3, 966	39	85	121	5, 957	673	6, 630
PSA 41	3, 818	1, 651	4, 200	70	0	131	9, 870	1, 249	11, 119
PSA 42	3, 232	938	5, 486	38	29	183	9, 906	965	10, 871
PSA 43	7, 335	2, 764	7, 703	129	13	506	18, 450	1, 962	20, 412
PSA 44–45	9, 858	4, 129	16, 269	142	0	301	30, 699	2, 823	33, 522
PSA 46	14, 854	11, 130	10, 072	357	63	1, 281	37, 757	4, 897	42, 654
PSA 47	13, 588	13, 640	15, 139	630	0	3, 487	46, 484	4, 645	51, 129
PSA 48	4, 730	3, 135	3, 449	107	0	2, 473	13, 894	1, 558	15, 452
WEST Region	64, 383	43, 207	72, 645	1, 740	191	9, 563	191, 729	20, 819	212, 548
1970									
PSA 31	948	583	1, 980	40	....	160	3, 711	542	4, 253
PSA 32	4, 105	3, 250	2, 545	150	....	350	10, 400	1, 100	11, 500
PSA 36	2, 452	1, 850	3, 506	82	....	280	8, 170	1, 000	9, 170
PSA 39	1, 744	1, 347	1, 200	89	....	620	5, 000	426	5, 426
PSA 30	1, 475	995	5, 120	50	75	185	7, 900	930	8, 830
PSA 41	5, 145	2, 450	5, 980	95	0	200	13, 870	1, 810	15, 680
PSA 42	3, 725	1, 135	7, 070	45	25	210	12, 210	1, 190	13, 400
PSA 43	10, 380	4, 000	11, 550	155	10	755	26, 850	3, 450	30, 300
PSA 44–45	14, 005	6, 000	24, 680	215	0	400	45, 300	4, 400	49, 700
PSA 46	21, 765	15, 400	15, 800	530	365	2, 240	56, 100	7, 300	63, 400
PSA 47	19, 240	19, 100	20, 000	930	0	5, 530	64, 800	7, 700	72, 500
PSA 48	7, 515	4, 610	5, 080	165	0	3, 830	21, 200	2, 400	23, 600
WEST Region	92, 499	60, 720	104, 511	2, 546	475	14, 760	275, 511	32, 248	307, 759
1975									
PSA 31	1, 377	850	3, 106	50	....	210	5, 593	777	6, 370
PSA 32	6, 315	4, 400	3, 600	210	....	425	14, 950	1, 550	16, 500
PSA 36	3, 468	2, 650	5, 045	110	....	347	11, 620	1, 380	13, 000
PSA 39	2, 732	1, 870	1, 853	143	....	770	7, 368	612	7, 980
PSA 30	1, 995	1, 480	6, 620	65	65	285	10, 510	1, 230	11, 740
PSA 41	6, 795	3, 640	8, 790	135	0	300	19, 660	2, 550	22, 210
PSA 42	4, 190	1, 340	8, 550	55	25	240	14, 400	1, 400	15, 800
PSA 43	13, 645	5, 600	18, 000	195	10	1, 100	38, 550	4, 950	43, 500
PSA 44–45	19, 720	8, 500	34, 600	320	0	540	63, 680	6, 120	69, 800
PSA 46	31, 130	21, 200	24, 700	780	400	3, 990	82, 200	10, 700	92, 900
PSA 47	27, 380	26, 800	27, 350	1, 370	0	12, 200	95, 100	10, 900	106, 000
PSA 48	10, 520	6, 760	7, 480	240	0	5, 900	30, 900	3, 500	34, 400
WEST Region	129, 267	85, 090	149, 694	3, 673	500	26, 307	394, 531	45, 669	440, 200

140 000

TABLE 7—Continued

Area	Rural and residential	Commercial	Industrial	Street and highway lighting	Electrified transportation	All other	Total to ultimate consumers	Losses	Total energy for load
1980									
PSA 31	2, 060	1, 210	4, 740	65	....	250	8, 325	1, 065	9, 390
PSA 32	9, 287	6, 128	5, 020	280	....	510	21, 225	2, 175	23, 400
PSA 36	4, 927	3, 650	7, 160	145	....	418	16, 300	1, 900	18, 200
PSA 39	4, 322	2, 440	2, 708	220	....	940	10, 630	870	11, 500
PSA 30	2, 725	2, 190	8, 540	80	55	440	14, 030	1, 650	15, 680
PSA 41	9, 060	5, 410	12, 700	185	0	445	27, 800	3, 620	31, 420
PSA 42	4, 600	1, 540	10, 000	60	20	280	16, 500	1, 600	18, 100
PSA 43	17, 920	7, 700	27, 400	240	10	1, 630	54, 900	7, 000	61, 900
PSA 44–45	26, 920	12, 100	48, 100	450	0	730	88, 300	8, 500	96, 800
PSA 46	44, 690	29, 400	38, 600	1, 160	450	6, 000	120, 300	15, 700	136, 000
PSA 47	38, 960	37, 600	36, 900	2, 050	390	19, 800	135, 700	15, 300	151, 000
PSA 48	14, 735	9, 940	11, 000	345	0	9, 210	45, 230	5, 070	50, 300
WEST Region	180, 206	119, 308	212, 868	5, 280	925	40, 653	559, 240	64, 450	623, 690
1985									
PSA 31	3, 042	1, 688	6, 890	90	....	290	12, 000	1, 400	13, 400
PSA 32	13, 135	8, 755	6, 840	370	....	600	29, 700	3, 000	32, 700
PSA 36	6, 969	4, 850	10, 065	180	....	496	22, 560	2, 540	25, 100
PSA 39	6, 542	3, 160	3, 718	330	....	1, 140	14, 890	1, 210	16, 100
PSA 30	3, 740	3, 250	11, 030	100	50	680	18, 850	2, 220	21, 070
PSA 41	12, 030	8, 030	18, 400	260	0	670	39, 390	5, 120	44, 510
PSA 42	5, 060	1, 750	11, 650	65	20	325	18, 870	1, 830	20, 700
PSA 43	23, 305	10, 600	40, 000	285	10	2, 400	76, 600	9, 400	86, 000
PSA 44–45	37, 520	16, 800	66, 000	600	0	980	121, 900	11, 400	133, 300
PSA 46	63, 970	40, 400	60, 500	1, 710	470	9, 050	176, 100	22, 900	199, 000
PSA 47	55, 560	52, 800	49, 500	2, 990	450	30, 300	191, 600	21, 400	213, 000
PSA 48	20, 755	14, 600	16, 300	485	0	14, 300	66, 440	7, 360	73, 800
WEST Region	251, 628	166, 683	300, 893	7, 465	1, 000	61, 231	788, 900	89, 780	878, 680
1990									
PSA 31	4, 450	2, 300	9, 790	130	....	330	17, 000	1, 800	18, 800
PSA 32	18, 235	12, 765	9, 110	440	....	700	41, 250	4, 050	45, 300
PSA 36	9, 590	6, 100	14, 002	220	....	588	30, 500	3, 300	33, 800
PSA 39	9, 400	4, 130	4, 730	500	....	1, 240	20, 000	1, 600	21, 600
PSA 30	5, 115	4, 830	14, 250	135	40	1, 040	25, 410	2, 980	28, 390
PSA 41	16, 050	11, 920	26, 600	360	0	1, 000	55, 930	7, 280	63, 210
PSA 42	5, 455	1, 900	13, 150	75	15	375	20, 970	2, 030	23, 000
PSA 43	30, 010	14, 500	57, 800	350	10	3, 530	106, 200	12, 500	118, 700
PSA 44–45	51, 850	23, 500	90, 000	830	0	1, 320	167, 500	15, 500	183, 000
PSA 46	91, 000	55, 800	94, 700	2, 500	500	13, 400	257, 900	33, 100	291, 000
PSA 47	77, 710	74, 000	66, 500	4, 390	500	45, 300	268, 400	29, 600	298, 000
PSA 48	28, 900	21, 500	23, 900	700	0	22, 100	97, 100	10, 900	108, 000
WEST Region	347, 765	233, 245	424, 532	10, 630	1, 065	90, 923	1, 108, 160	124, 640	1, 232, 800

TABLE 8

West Region—Distribution of Total Energy for Load by Power Supply Areas

[percent]

	PSA 31	PSA 32	PSA 36	PSA 39	PSA 30	PSA 41	PSA 42	PSA 43	PSA 44–45	PSA 46	PSA 47	PSA 48	West Region
Rural and residential:													
1965	21.9	32.3	26.6	28.2	16.2	34.3	29.7	35.9	29.4	34.8	26.6	30.6	30.3
1970	22.3	35.7	26.7	32.1	16.7	32.8	27.8	34.3	28.2	34.3	26.5	31.9	30.0
1980	21.9	39.7	27.1	37.6	17.4	28.8	25.4	29.0	27.8	32.9	25.8	29.3	28.9
1990	23.7	40.3	28.4	43.5	18.0	25.4	23.7	25.3	28.3	31.3	26.1	26.8	28.2
Commercial:													
1965	14.0	31.4	19.9	27.8	10.1	14.9	8.6	13.5	12.3	26.1	26.7	20.3	20.3
1970	13.7	28.3	20.2	24.8	11.3	15.6	8.5	13.2	12.1	24.3	26.3	19.5	19.7
1980	12.9	26.2	20.1	21.2	14.0	17.2	8.5	12.4	12.5	21.6	24.9	19.7	19.1
1990	12.2	28.2	18.0	19.1	17.0	18.8	8.3	12.2	12.8	19.2	24.8	19.9	18.9
Industrial:													
1965	45.8	22.9	38.3	21.8	59.8	37.8	50.5	37.8	48.5	23.6	29.6	22.3	34.2
1970	46.6	22.1	38.2	22.1	58.0	38.2	52.7	38.1	49.6	24.9	27.6	21.5	34.0
1980	50.5	21.4	39.3	23.5	54.5	40.4	55.3	44.3	49.7	28.4	24.5	21.9	34.1
1990	52.1	20.1	41.4	21.9	50.2	42.1	57.2	48.7	49.2	32.5	22.3	22.1	34.5
All other:													
1965	5.3	4.8	4.2	14.1	3.7	1.8	2.3	3.2	1.3	4.0	8.1	16.7	5.4
1970	4.7	4.3	4.0	13.1	3.5	1.9	2.1	3.0	1.2	5.0	8.9	16.9	5.8
1980	3.4	3.4	3.1	10.1	3.7	2.0	2.0	3.0	1.2	5.6	14.7	19.0	7.5
1990	2.4	2.5	2.4	8.1	4.3	2.2	2.0	3.3	1.2	5.6	16.9	21.1	8.3
Total to ultimate consumers:													
1965	86.9	91.4	89.0	91.9	89.8	88.8	91.1	90.4	91.6	88.5	90.9	89.9	90.2
1970	87.3	90.4	89.1	92.1	89.5	88.5	91.1	88.6	91.1	88.5	89.4	89.8	89.5
1980	88.7	90.7	89.6	92.4	89.5	88.5	91.2	88.7	91.2	88.5	89.9	89.9	89.7
1990	90.4	91.1	90.2	92.6	89.5	88.5	91.2	89.5	91.5	88.6	90.1	89.9	89.9
Losses:													
1965	13.1	8.6	11.0	8.1	10.2	11.2	8.9	9.6	8.4	11.5	9.1	10.1	9.8
1970	12.7	9.6	10.9	7.9	10.5	11.5	8.9	11.4	8.9	11.5	10.6	10.2	10.5
1980	11.3	9.3	10.4	7.6	10.5	11.5	8.8	11.3	8.8	11.5	10.1	10.1	10.3
1990	9.6	8.9	9.8	7.4	10.5	11.5	8.8	10.5	8.5	11.4	9.9	10.1	10.1
Total energy for load:													
1965	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1970	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1980	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1990	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

The West Region summer load curve has two separate peaks, with the system peak occurring between 1:00 and 2:00 p.m. and with the secondary peak between 7:00 and 8:00 p.m. due to the early evening residential loads. The three PSA's follow a similar pattern; however the peaks for PSA's 32 and 43 are at different times. The winter load curves also have two separate peaks with the evening peak load considerably greater than the mid-morning peak. The summer peak represents a smooth curve indicating high demands over a long period of time while the winter peak represents a sharp curve for the system peak. This also indicates the seasonal effect on system peaks.

WEST REGION

FPC Form No. 15-A

SUMMER DAILY LOAD CURVES

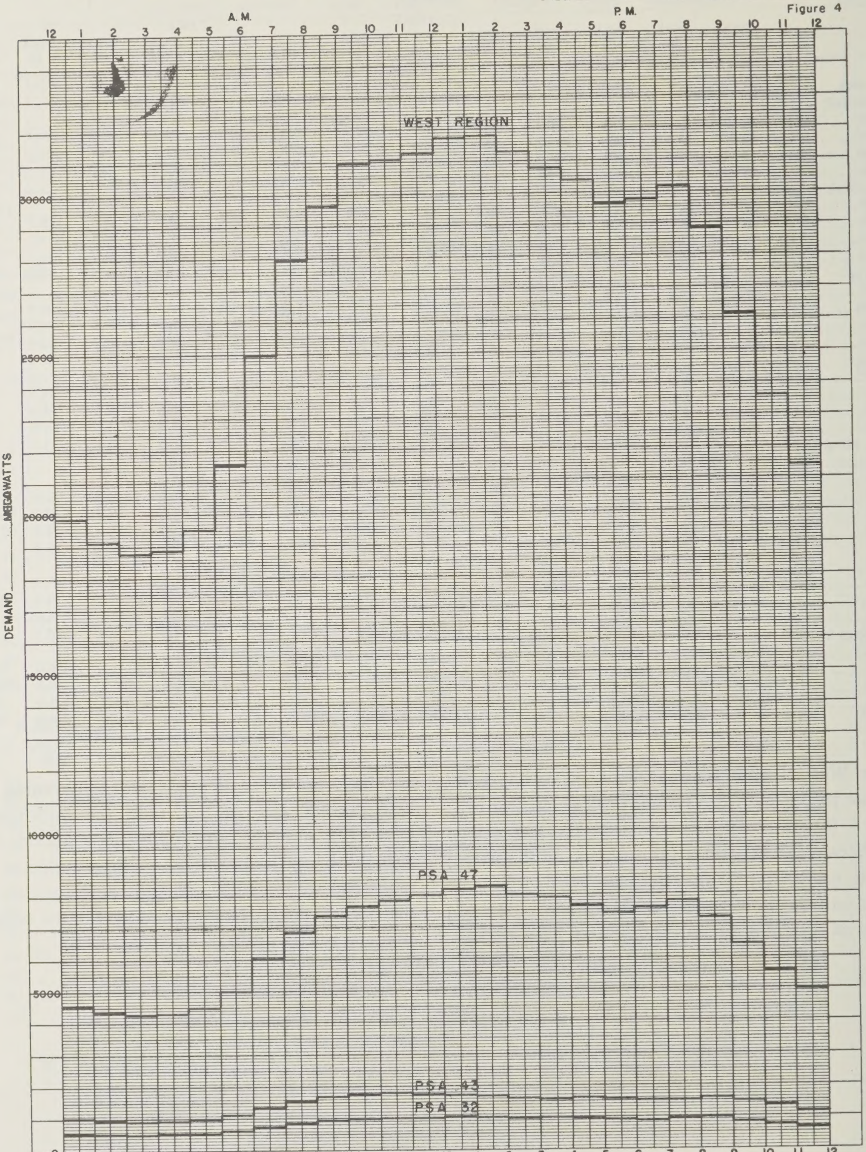
FEDERAL POWER COMMISSION

1965

PREPARED BY SFRO DATE 1/9/69

CHECKED BY DATE

Figure 4



NOTES: PACIFIC STANDARD TIME USED AS A REFERENCE FOR WEST REGION, P.S.A. 43 AND 47, MOUNTAIN STANDARD TIME USED FOR P.S.A. 32.

DAILY LOAD CURVE SHEET

TYPE OF DAY

FRIDAY 8/6/65

DAY OF WEEK AND DATE

COMPANY OR SYSTEM

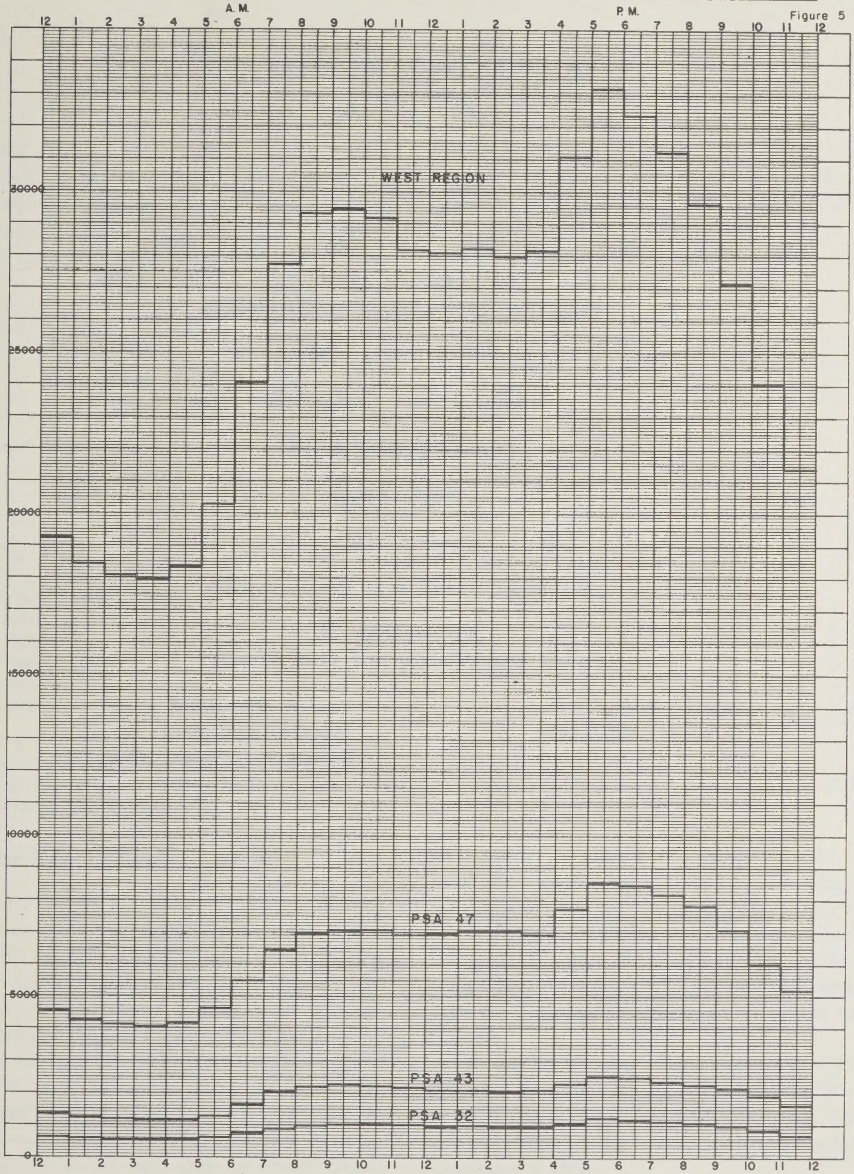
WEST REGION

FPC Form No. 15-A
FEDERAL POWER COMMISSION

WINTER DAILY LOAD CURVES

1965

PREPARED BY SFRO DATE 1/10/69
CHECKED BY DATE



NOTES: PACIFIC STANDARD TIME USED AS A REFERENCE FOR WEST REGION, P. S. A. 43 AND P. S. A. 47
MOUNTAIN STANDARD TIME USED FOR P. S. A. 32.

DAILY LOAD CURVE SHEET

TYPE OF DAY

TUESDAY 12 / 7 /65
DAY OF WEEK AND DATE

COMPANY OR SYSTEM

Report to
West Regional Advisory Committee

National Power Survey

Federal Power Commission

LOAD FORECASTS

1965–1990

April 6, 1967

(Adopted by W.R.A.C., as Revised June 7, 1967)

Subcommittee on
Power Requirements and Load Diversity

John J. Bugas
Bernard Goldhammer
Paul A. Blanchard
Marshall L. Blair
Robert P. O'Brien, Chairman

WEST REGION LOAD FORECASTS
1965–1990

Summary

The staff in the San Francisco office of the Federal Power Commission, under the direction of the Regional Engineer, has prepared a forecast of the use of electrical capacity and energy in the West Region by five-year intervals from 1965 to 1990. A summary of this forecast of growth in electrical demands, which is indicative of the need for adding capacity to meet these anticipated future loads is summarized briefly on the following table.

Federal Power Commission—West Region [1]

	Regional grouping—power supply areas		
	V & VI	VII	VIII
Peak Demand, Mw:			
1965	3, 896	14, 537	19, 333
1970	5, 791	20, 900	28, 200
1975	8, 034	28, 900	40, 500
1980	10, 767	39, 800	58, 400
1985	14, 211	54, 400	84, 300
1990	18, 528	74, 300	122, 000
Annual Average Increase, Mw:			
1965–1970	379. 0	1, 272. 6	1, 773. 4
1970–1975	448. 6	1, 600. 0	2, 460. 0
1975–1980	546. 6	2, 180. 0	3, 580. 0
1980–1985	688. 8	2, 920. 0	5, 180. 0
1985–1990	863. 4	3, 980. 0	7, 540. 0

[1] Percentage growth rates and data by power supply areas are shown on Tables A, B, and C of Appendix A.
Demand data presented here and in Tables A, B, and C were revised as a result of this and other reviews. See Table 4. Appendix 1 for revised demand data.

Subcommittee Review

The area covered by the staff study is indicated on the map (Chart A, Appendix A) showing that part of the western United States which for this purpose was designated the West Region, the boundaries of FPC Power Supply Areas involved, and the combination of P.S.A.'s which are grouped for study purposes into FPC Power Supply Regions V, VI, VII, and VIII.

The staff forecast was prepared essentially by trending recorded kilowatt-hour sales data by major functional classes of use, and by power supply areas. Although certain modifications to the individual estimates were made as seemed proper to recognize significant local conditions, certain other local factors referred to in the comments by areas were given insufficient recognition. The sales forecasts for each five-year period were accumulated to a power supply area total and then used as the basis for deriving a peak demand and load factor estimate. The demand and kilowatt-hour estimates were then combined into the power supply region estimates.

To assist the regional offices, the Bureau of Power prepared and issued a comprehensive set of "Guidelines" which was issued June 3, 1966, and supplemental criteria for use in field studies under date of September 3, 1966.

Since the power supply area boundaries in most cases coincide with boundaries between areas served by major utilities or groups of utilities, and

since members of the subcommittee were well dispersed geographically, it was decided that the subcommittee would not attempt to audit the staff forecast in detail, but would check the estimates by power supply areas against similar forecasts available in the local areas. Detailed responses were received from subcommittee members or from utility representatives in the areas and are reflected in revised estimates in Table 4.

Inasmuch as the Guidelines and criteria prescribed by the Bureau of Power could have significant impacts upon the forecasts, members of the subcommittee were invited to submit such observations as they deemed appropriate concerning the basic assumptions.

The remainder of this report is devoted to a summarization of the comments and conclusions of the subcommittee as a result of this review of the staff forecasts.

Forecast Methods

It is perhaps timely to start this review with a reminder that a conclusion can have no greater accuracy than that of its least accurate constituent element. In the development of electrical systems, Action Planning, that is, the preparation of designs, placing of orders, and construction of facilities, falls in a time period of five years or less for the great majority of plant additions. Some hydro projects and some new developments such as initial nuclear generating stations could run somewhat longer.

Because load growth forecasts must, as a routine activity, be prepared in connection with these expansion programs, most utility operators have substantially greater confidence in and place greater reliance upon the short-run five-year forecasts. Because the longer range forecasts of necessity require more sweeping and more generalized basic assumptions, and because over the years, experience has shown that subsequent events can and do depart materially from earlier plausible inferences, the industry is inclined to look upon longer range forecasts as much less precise and subject to much larger margins of error.

This background against which load forecasts of electric system requirements are prepared and evaluated suggests two fundamental points which should be made clear in reports to the general public, whose experience does not normally prepare them to so interpret the results. First, any report on load forecasts should make it perfectly clear to the reader that any forecast of a quantity of power or energy twenty years hence, even under the best of circumstances, probably has a range of accuracy which would permit relatively large variations in the answers. Secondly, an independent check made of such a forecast which produces results which fall within this reasonable accuracy range, is considered a corroboration of the forecast being tested.

The desirability of the staff use of individual consumption categories as a basis of trend forecasts for the longer range period was questioned by a number of members of the subcommittee. The consensus was that while forecasts by individual classes of service were useful for five-year forecasts or even for 10-year projections, because developments within classes which affect the trends were so obscure or unpredictable beyond those periods, that longer range trend assumptions were open to substantial question, were of doubtful accuracy, and could be of limited utility. Consequently, answers based on such procedures for the long-term could have imputed to them by the lay reader a much greater accuracy or plausibility than the underlying data would justify. This is not to say that the use of such methods as a check or test procedure might not be useful or desirable in certain cases and could add to the fund of information generated by the forecasting effort.

One further caution that should be observed in attempting to segregate sales data by classes of customers and, more particularly, categories of use is that modern tariff design for many years has been trending away from rates designed for specific types of use and has been directed toward rate schedules that imposed proper charges for the characteristic of the service on the utility side of the meter. Schedules of that character relieved the utility of the major job of policing customer's activities and permitted further simplification in rate form. As is obvious, however, it makes much more difficult any attempts to identify certain classes or kinds of load in historical records for the purpose of deriving trends. Two examples of this difficulty for one of the major companies can be stated briefly. A large part of the agricultural service is served on an agricultural and pumping schedule. In addition, the domestic schedules permit domestic farm service to be served through the domestic meter. If the farmer should find that lower rates could be obtained by using what is generally thought of as the Commercial or Small Industrial schedule, that also is available. Concurrently, the schedule which is used for heavy

agricultural pumping is also available for use on water supply systems. Domestic water companies, both privately-owned and governmental operations, are eligible for service. With such intermingling of both kinds of uses and classes of customers, broad summarizations for large areas involving many companies are, to say the least, suspect from the beginning.

Forecast Assumptions Used

To the extent that the staff forecasts may have been affected by some of the prescribed assumptions, the subcommittee also considered the validity of the assumptions. The field staff was instructed to use an annual rate of increase in the Gross National Product of 4% in 1958 constant dollars. The Joint Economic Committee of Congress advised the FPC to use such a figure for the period 1965–1975. The Bureau of Power arbitrarily adopted the figure for use for the balance of the study. A review of the historical GNP performance between 1946 and 1965 indicates an annual *average* increase of 3.32% and a *compound* rate of growth of 3.25%. Over a 25-year period, the difference between a 3.25% rate of growth and a 4% rate is 20%. While this may not be a significant difference on a percentage basis, a difference of that amount in Region VIII in 1990 would be 12,000 Mw, or more than half the total peak demand in 1965, which can be seen by reference to the summary tabulation.

Another example of an underlying "assumption" which could seriously affect the forecast results is the recommended use of a 5% annual growth rate for the Federal Reserve Board Index of Industrial Production, a rate for use in the the period 1965–1975 also suggested by the Joint Economic Committee. Instead of using this growth rate at a constant level, the Bureau of Power instructed field offices to use a rate of 4⅔% for the period 1975–1985 and a 4½% rate for the 1985–1990 period. An analysis of the historical data indicates that the average annual increase between 1947 and 1965 was 4.26% and the range varied from a high of 11.0% in 1964–1965 to a low of −7.0% in 1957–1958. A compound rate of growth of 4.42% defines the historical change from 1947 to 1965.

In the 1964 National Power Survey and in the Guidelines issued in connection with this present revision, considerable attention has been focused on the potential for cost reduction in a number of areas. While such cost reductions may appear to be attainable in the future in terms of constant dollars, it is strongly emphasized that the effect of cost savings on rates could be offset by continuning inflation. Furthermore, reductions in production costs do not have a proportionate effect on costs at distribution sales levels. Cost increases associated with locating production facilities in areas more remote from urban developments to improve aesthetics or to achieve air pollution reductions and the potentially heavy cost of putting distribution facilities underground to achieve "beautility," all of which are expected to be accompanied by persistent, if not increasing, inflation, suggests the strong possibility that prices for electricity will have a greater tendency to rise than to fall. Even so, the effect on sales should be negligible, for there is little or no evidence of a direct relationship for most classes of service between the cost of electricity and its volume of use at prevailing rate levels or at rate levels which may result from the cost changes discussed above. As the 1964 Survey correctly observed, the use of electricity can be influenced more significantly by the cost of utilization facilities.

Forecasts

The specific comments of members of the subcommittee or local utility representatives in the several power supply areas can be summarized succinctly in the following comments. The complete response is included in the Appendix.

PSA 32.—The staff forecast for the period 1965–1980 is substantially correct. The forecast for the period 1980–1990 appears to be a little low. It appears that a more reasonable annual compounded rate of growth for this period would be 6%.

PSA 39.—The staff forecast indicating a gradual leveling off in rate of growth appears reasonable. 1965 data used compares closely with recorded data.

PSA 42, 43, 44, 45.—Data prepared by the Load and Resource subcommittee of the West Group of the Northwest Power Pool, while not entirely coextensive with the staff forecast areas, tends to support the staff trends. However, in two specific areas there may be some question about the results because of faulty assumptions. In one case the distribution of population by power supply areas for subsequent years is assumed to be the same as the

1960 distribution. This is contrary to recent experience which is expected to continue. In the second case average use per customer is assumed to increase at a rapid rate not supported by the slackening rates of increase reflected in the 1950–65 data.

PSA 46.—The test of staff load estimates was made by adding to the estimate for the P.G.&E. system, estimates for Sierra Pacific Power Company, Modesto and Turlock Irrigation Districts, and pumping loads of the Central Valley and State Water Projects. In the first 10 to 15 years of the estimating period the increment of new pumping loads increases the total area rate of growth. In the latter part of the period the increment is smaller in relation to total load and depresses the total area rate of growth. For 1970 and 1975 the staff estimates compare very well with the composite utility estimate. In 1980 the two estimates begin to depart from one another and by 1990 the staff estimates are 19% higher for energy and 23% higher for peak. The reason for this divergence is the basic growth rates reflected in the utility estimates of 6.9%—1975–80; 6.8%—1980–85; 6.7%—1985–90, which were reduced somewhat by adding the pumping load increments as contrasted to the growth rates of almost 8% used by the staff.

PSA 47.—The staff estimated rates of growth for 1965–1990 may be optimistically high because of recent changes which may indicate a permanent alteration in growth trends involving decreased industrial development, decreased job creation, and slackening of net in-migration. An analysis of the staff category of use "ALL OTHER" where it is assumed the energy used for pumping in the State Water Project aqueduct is included, suggests that the forecast may not adequately reflect this latter load. A graph showing the estimate for the category after being reduced by pumping requirement of the State Project indicates that growth would be suspended for other uses in the category from 1970 to 1975 if in fact the pumping requirements were not omitted. Some verification of this apparent discrepancy seems justified. Increased use per customer and state pumping loads which tend to offset the adverse factors lead to the conclusion that at least for the present the staff estimates may be used.

PSA 48.—The staff estimate for PSA 48 appears to be reasonably accurate and should not be changed at this time.

Area Trends of Significance:

PSA 39, 48.—Large new coal mining installations as a source of fuel for electric generation at both minemouth locations and at the most convenient nearby source of cooling water have brought into existence factors which can significantly change the rate of industrial growth in certain areas of the southwest which have heretofore not had such an abundance of the essential ingredients for expansion. Almost all of the basic resources for power generation are, however, subject to heavy conflicts of one type or another, and the rate and extent at which the growth potential will be realized is not at this time at all clear. Fuel and transportation economics, air and water pollution, competitive uses for land and water, and many other factors must be resolved project by project and item by item before sound and acceptable arrangements can be concluded.

PSA 42, 43, 44, 45.—It is anticipated that winter loads will continue to increase as more electrical space heating loads are added. Substantial increases in industrial loads are also expected which add load on a fairly uniform year-around basis.

PSA 46.—Increases in air conditioning loads in milder climates, because of its growing acceptance as a necessity, will increase summer loads which will tend to maintain predominantly summer peaks in Area 46. In other areas this could influence shifts from winter to summer peaks. Electric space heating is expected to increase, but will depend upon competitive pressures from fossil fuels. The extensive use of nuclear generation could have a favorable effect on production costs and may offset some of the adverse cost effects of underground distribution.

PSA 47.—The rapid acquisition of a number of new and remote sources of capacity and energy raises many interesting problems with respect to operation of integrated systems, costs of resources at load center, and system operating reliability and economics. Canadian exchange and Pacific surplus capacity and energy, transmission for more than 1,000 miles over new 500 Kv A.C. and 750 Kv D.C. lines, dependence on high load factor large size coal units 300 to 500 miles distant by 500 Kv A.C. lines, new large-size nuclear units, both single purpose and dual purpose (with sea water desalination) all involve operating and economic consequences which will become known with accuracy as experience is gained in their operation.

In distribution areas, continuing trends toward greater use of underground facilities and continued increases in the average use per customer in residential installations are anticipated.

Recommendation

It is recommended that the San Francisco Regional Office review and revise its load estimates in the light of the comments presented under the earlier heading, FORECASTS.[1]

[1] In connection with this recommendation, the Commission Staff, on April 28, furnished the Committee with revised figures for Power Supply Areas 46 and 47, which reduced the estimates of demand in Power Supply Area 46 by amounts 2% or less than the January estimate, and increased the demand estimates of Power Supply Area 47 by amounts of 2.6% or more.

356-240 O—70——21

APPENDIX A

Map
Regional and Area Boundaries

SUMMARY

ESTIMATED DEMANDS

CHART A

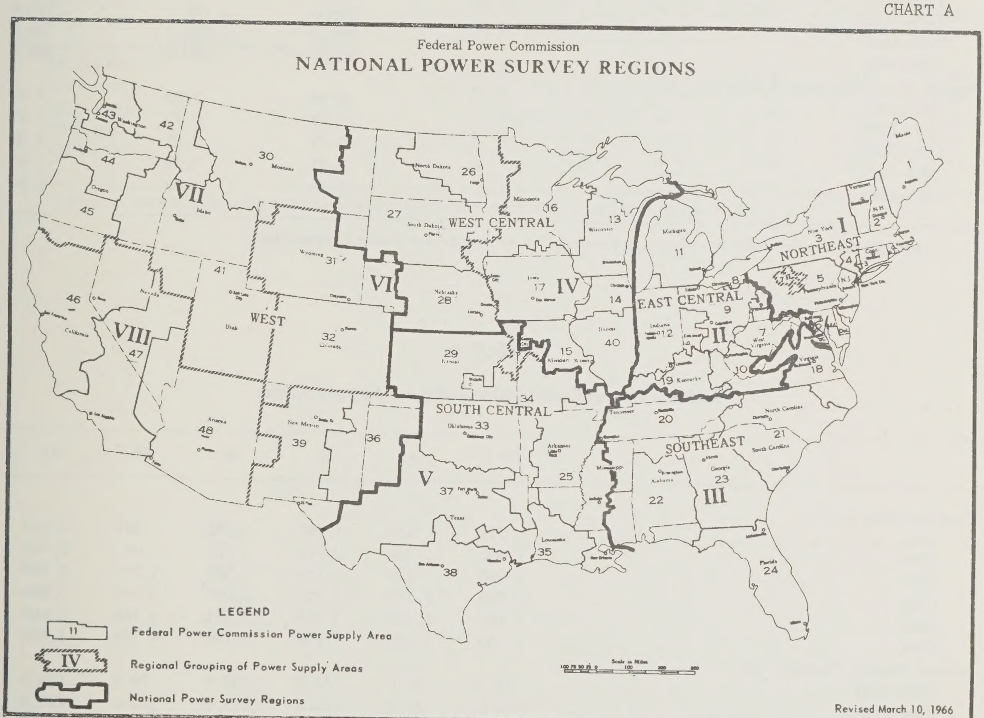


TABLE A

Federal Power Commission—Regional Groups

	V & VI	VII	VIII
Peak Demand, Mw [1]:			
1965	3, 896	14, 537	19, 333
1970	5, 791	20, 900	28, 200
1975	8, 034	28, 900	40, 500
1980	10, 767	39, 800	58, 400
1985	14, 211	54, 400	84, 300
1990	18, 528	74, 300	122, 000
Annual Average Increase, Mw:			
1965–1970	379. 0	1, 272. 6	1, 773. 4
1970–1975	448. 6	1, 600. 0	2, 460. 0
1975–1980	546. 6	2, 180. 0	3, 580. 0
1980–1985	688. 8	2, 920. 0	5, 180. 0
1985–1990	863. 4	3, 980. 0	7, 540. 0
Annual Compound Rate of Increase, %:			
1965–1970	8. 25	7. 53	7. 84
1970–1975	6. 77	6. 70	7. 51
1975–1980	6. 03	6. 61	7. 59
1980–1985	5. 71	6. 45	7. 62
1985–1990	5. 45	6. 43	7. 67

[1] Demand data in this table have been superseded. See revised data in Table 4, appendix 1.

TABLE B

Federal Power Commission—Power Supply Areas

	30	31	32	36	39	41
Peak Demand, Mw [1]:						
1965	1, 090	474	1, 497	1, 238	687	2, 044
1970	1, 460	704	2, 271	1, 775	1, 041	2, 840
1975	1, 940	930	3, 155	2, 380	1, 569	4, 020
1980	2, 590	1, 193	4, 226	3, 089	2, 259	5, 690
1985	3, 490	1, 505	5, 555	3, 991	3, 160	8, 060
1990	4, 700	1, 880	7, 190	5, 190	4, 268	11, 460
Annual Average Increase, Mw:						
1965–1970	74. 0	46. 0	154. 8	107. 4	70. 8	159. 2
1970–1975	96. 0	45. 2	176. 8	121. 0	105. 6	236. 0
1975–1980	130. 0	52. 6	214. 2	141. 8	138. 0	334. 0
1980–1985	180. 0	62. 4	265. 8	180. 4	180. 2	474. 0
1985–1990	242. 0	75. 0	327. 0	239. 8	221. 6	680. 0
Annual Compound Rate of Increase, %:						
1965–1970	6. 02	8. 23	8. 69	7. 47	8. 67	6. 80
1970–1975	5. 85	5. 73	6. 80	6. 04	8. 55	7. 20
1975–1980	5. 95	5. 11	6. 02	5. 35	7. 56	7. 20
1980–1985	6. 15	4. 76	5. 62	5. 26	6. 94	7. 21
1985–1990	6. 13	4. 55	5. 30	5. 39	6. 20	7. 29

[1] Demand data in this table have been superseded. See revised data in Table 4, Appendix 1.

TABLE C

Federal Power Commission—Power Supply Areas

	42	43	44–45	46	47	48
Peak Demand, Mw[1]:						
1965	1, 562	4, 048	6, 013	7, 639	9, 451	2, 941
1970	2, 190	5, 760	8, 930	11, 400	13, 300	4, 480
1975	2, 580	8, 280	12, 550	16, 600	18, 800	6, 540
1980	2, 950	11, 780	17, 400	24, 300	26, 700	9, 560
1985	3, 380	16, 360	23, 960	35, 600	37, 900	14, 000
1990	3, 750	22, 580	32, 900	52, 200	53, 600	20, 500
Annual Average Increase, Mw:						
1965–1970	125. 6	342. 4	583. 4	752. 2	769. 8	307. 8
1970–1975	78. 0	504. 0	724. 0	1, 040. 0	1, 100. 0	412. 0
1975–1980	74. 0	700. 0	970. 0	1, 540. 0	1, 580. 0	604. 0
1980–1985	86. 0	916. 0	1, 312. 0	2, 260. 0	2, 240. 0	888. 0
1985–1990	74. 0	1, 244. 0	1, 788. 0	3, 320. 0	3, 140. 0	1, 300. 0
Annual Compound Rate of Increase, %:						
1965–1970	6. 99	7. 31	8. 23	8. 34	7. 07	8. 78
1970–1975	3. 33	7. 53	7. 04	7. 81	7. 17	7. 86
1975–1980	2. 72	7. 31	6. 75	7. 92	7. 27	7. 89
1980–1985	2. 76	6. 79	6. 61	7. 94	7. 26	7. 93
1985–1990	2. 10	6. 66	6. 55	7. 96	7. 18	7. 93

[1] Demand data in this table have been superseded. See revised data in Table 4, Appendix 1.

APPENDIX 2

ENERGY SUPPLY AND DEMAND FOR THE WEST REGION

Prepared by Task Force on Fuels (Subcommittee on Generation)

A. Summary and Conclusions

The principal results of the National Power Survey 1968 review of fuels for electric generation made by the various electric generating utilities located in FPC Power Supply regions VI, VII and VIII which collectively comprise the West Region for the National Power Survey, are shown on the following tabulation.

The survey disclosed that by 1990 total use of energy is expected to more than double, electric generation will increase five-fold and production of electricity by thermal plants will increase by a factor of 10 or more. This growing demand will require a raw energy input of 22,608 trillion Btu's in 1990 as compared with 10,721 trillion Btu's in 1970. See summary table below and Table 1, Appendix 2.

Total estimated recoverable energy reserves in the West Region are about 25 times greater than the cumulative projected requirements to 1990 thus indicating internal energy self-sufficiency. Coal comprises about 56% of this reserve but is expected to furnish only about 10% of energy used by 1990. The remote location of many of the coal deposits from load centers is a basic reason for estimates of its relatively low use. The coastal states are expected to make increasing use of nuclear reactors to supply energy needs while the Rocky Mountain states continue to utilize coal.

Although the selection of alternative fuels is an economic one—finding the lowest cost supply—the selection is constrained by limited availability of cooling water and by many public policy decisions including oil imports, pricing of gas, environmental controls, and regulation of nuclear plant siting. Fuel mix projections based upon the current outlook, which is the transient resultant of the inter-reaction of such forces, are not valid beyond a point in time wherein a major change could develop in any one of such physical or policy determinants. This could be as little as five years from now.

Individual fossil fuel prices are expected to increase during the forecast period. However, the expanding use of coal for thermal generation at lower relative costs results in an overall decrease of about 0.5% per year in the cost of electric energy to be generated. Nuclear fuel costs are estimated to decline at about 2% per year. It is expected that the fuel component (including nuclear fuel) of thermal generation will average about 16 cents per million Btu's of equivalent heat in 1990, as compared to 28 cents in 1970, based on new plants in latter part of forecast period.

That coal, the dominant proved energy resource of the West Region, will fall behind uranium as raw material for conversion to electric energy is a conclusion based upon: (1) cost factors; (2) the very severe limitation on the amount of water available for mine-mouth plants or plants located outside of the metropolitan areas of the Southwest; and (3) air pollution control considerations which preclude the use of coal in the California load centers. Progress in the development of dry cooling, EHV transmission, or clean fuel-combustion gas cycles may enhance coal's potential, but for the period of this study, the relative economics and policy considerations favor nuclear generation. One of the findings of this survey as compared with the 1964 National Power Survey is the change in projected thermal generation in the Pacific Northwest Subregion from substantially all coal to substantially all nuclear (see Table 7). This change primarily reflects cost factors. Economically recoverable coal deposits are scarce in the vicinity of major load centers in this area.

As to natural gas, while the ultimate recovery in the West and areas supplying the West is limited, projections of requirements, discovery, proved reserves, and unproved or undiscovered gas remaining in the ground suggest that the electric utility industry in contemplating the construction after the mid-1970's of any fossil fuel plants proposing the use of natural gas as the primary fuel should carefully study the then situation. The projections in this report indicate that plants constructed before then will have adequate supplies of gas but that

Summary of 1968 West Region Survey of Fuels for Electric Generation—National Power Survey

	1965		1970		1980		1990	
	Quantity	Percent of total	Quantity	Percent of total	Quantity	Percent of total	Quantity	Percent of total
1. Population (Thousands)	31, 006	....	34, 650	....	43, 400	....	54, 241	....
2. Total Energy Use (10^{12} Btu)	8, 904	100	10, 721	100	15, 585	100	22, 608	100
% Consumed for Electric Generation		25	....	29	....	39	....	52
% Consumed for Thermal Elec. Generation		11	....	14	....	28	....	43
3. Total Elec. Utility Generation (Billion kwh)	209	100	308	100	631	100	1, 205	100
Thermal Elec. Utility Generation (Billion kwh)	89	43	149	48	447	71	1, 007	84
4. Fuel Use for Thermal Elec. Utility Generation		100	....	100	....	100	....	100
(a) Coal (Thousand short tons)	7, 729	14	15, 496	20	59, 264	28	98, 536	21
(b) Natural Gas (Billion Cubic Feet)	628	72	855	63	685	17	724	8
(c) Uranium (Short tons U_3O_8)	14	1	1, 027	5	8, 175	47	15, 640	67
(d) Thorium (Short tons ThO_2)					3	....	100	1
(e) Oil, No. 6 (Thousands bbl.)	18, 555	13	7, 705	4	1, 400	....	1, 425	....
(f) Oil, Low Sulfur (Thousands bbl.)			16, 000	8	49, 375	8	46, 000	3
5. Average Heat Rate, Fossil Fueled Thermal Elec. Generation (Btu/kwh)	10, 412	....	9, 865	....	9, 471	....	9, 718	....
6. Fuel Price Estimates (¢/M ^{2} Btu), excluding Transmission:								
(a) Coal	16		15		16		17	
(b) Natural Gas	30		31		34		36	
(c) Uranium	26		20		15		13	
(d) Thorium			20		15		13	
(e) Oil, No. 6	32		32		28		32	
(f) Oil, Low Sulfur			41		42		44	
7. Fuel Reserves:								
(a) Coal (Million Short Tons, 1968)	263, 230							
(b) Natural Gas (Billion Cubic Feet, 1966)	30, 464							
(c) Uranium (Short Tons U_3O_8, 1968)	148, 000							
(d) Thorium (Short Tons ThO_2, 1968)	100, 000							
(e) Oil, No. 6 (Million bbl., 1966) (15% of Crude & Shale Oil Reserves)	101, 026							
(f) Low Sulfur Oil (Million bbl.)								

thereafter further increase should not be contemplated.

Nuclear energy is estimated to increase to about 46% of thermal generation by 1980 and 70% by 1990. This estimated increase is based upon the current outlook which favors nuclear generation partly because of air pollution considerations and lower costs and partly due to the economies of scale in the construction of large multi-ownership plants located close to the load centers. Although this appraisal may appear somewhat overoptimistic in view of the nuclear plant siting situation, the study did not find persuasive evidence that coal's inherent disadvantages would be overcome through reduced production costs and development of clean fuel or combustion gas cleaning in time to alter the relationship during the time covered. Even with this substantial growth, it is projected that costs of uranium concentrate may increase only $1.00 to $2.00 per pound by 1990. Nuclear fuel costs per kwh may actually decline if anticipated improvements materialize in the fuel cycle and reactor design.

The use of conventional domestic residual fuel oil is expected to be essentially eliminated in Southern California by 1975. (Only about 5% of the 1975 oil use is estimated to be conventional residual oil). This is because of air pollution control considerations and the higher sulfur content of conventional oil, most of which has been used in the Southern California area. The price of such conventional oil is expected to remain fairly stable because its production will be closely tailored to market demands by the refiners.

Southern California utilities are being compelled to substitute low sulfur oil at an initial cost premium of 28% and the cost of low sulfur oil is expected to increase in the future at about 0.35% per year. The supply of low sulfur oil is thought to be adequate if a combination of some domestic production and imported oil, made available through Federal oil import control regulations in recognition of its need for air pollution control purposes, can be made. Federal oil import regulations are administered for a grouping of states called Petroleum Administration District V, which includes California, Arizona, Nevada, Oregon, Washington, Alaska and Hawaii. Substantially all of the oil and gas-fired generating units operated by the utilities responding to this survey are in District V which also includes the requirements for the State of Hawaii, estimated to be about five million barrels in 1970. Much of the Hawaiian oil requirements also will have to be satisfied with low sulfur oil because of air pollution control pressures. Because its low sulfur oil supply, along with that of the West Region, will depend upon District V oil import control regulations, Hawaii, and possibly Alaska, might well be included in the West Region total resource-requirements picture.

The mix of fuel used for electrical power generation is influenced by changes in public policy in response to environmental controls, nuclear plant siting, water supply for industry, drastic short-notice changes in capital costs for certain types of generating equipment, transmission costs and technological changes. Since all these factors affect fuel preference and thus the fuel mix, it is concluded that projections beyond about five years are not realistic. As an example, coal-fired plants located in Arizona and New Mexico are being considered and if prerequisites are met, would go into service in 1974, 1975 and 1976. If required factors are not attained, other sources of energy would be used. Nevertheless, such forecasts are useful for general long-range planning of new generating plants that will be added during the balance of this century.

B. Introduction

This report was prepared by the Task Force on Fuels for the West Regional Advisory Committee of the Federal Power Commission. The West region essentially includes the eleven Western States and although the boundary as defined by the Federal Power Commission does not follow State borders (See Map 1), an attempt has been made to adjust data in such a manner that it can be presented on a State basis. For purposes of data gathering, the West Region was divided into subregions as follows:

Northwest Subregion: Idaho, Montana, Oregon, Washington, Wyoming

Rocky Mountain Subregion: Arizona, Colorado, Nevada, New Mexico, Utah

California

The purpose of this report is to present data on the distribution, production, and consumption of fuels in the West Region, particularly as they are used for electrical power generation. Historical data are presented in the accompanying tables and charts. In addition to historical information, future trends in the fuel mix are considered to the year 1990. The increasing rate of change, both technological and sociological, makes projection of the fuel

mix for electrical power generation hazardous beyond a five-year period. Data presented for 1975 and beyond is to be regarded, therefore, as a forecast. As an example, the 1968 discovery of large oil and associated gas reserves in Alaska may have a substantial effect on utilization of fuel in the West Region. Such major findings completely change energy projections. Although the uncertainties become great beyond five years, such forecasts do serve a useful purpose. They show trends which, when analyzed, may call attention to forthcoming changes. Utility companies and others are thus prepared for such changes even though timing may not be exact.

The West Region utilizes a complete mix of energy sources for electrical power. In the Northwest Subregion, hydro power plays a very important role along with nuclear and coal thermal plants. In the Rocky Mountain Subregion, coal is the predominant fuel, while in California, oil and natural gas with hydro power compose the fuel mix. As utilities in the West Region become more strongly linked by reliable interties, the fuel mix will become controlled less by local conditions and more by overall regional changes in fuel cost and availability. Hydro power, for example, from the Northwest Subregion can now supply energy for California. Coal in New Mexico supplies energy used in Los Angeles.

In this respect, the West Region differs from much of the rest of the United States. Water is in short supply in much of the region, distances between load centers are great, and fuel resources are frequently remotely located from use areas. As a result, transportation and transmission costs are vital factors in siting power plants, and, therefore, in fuel selection.

Transportation costs for nuclear fuel is minimal—about 0.02 mills per kwh. Therefore, it would be expected that nuclear plants would be prime contenders, especially in the population centers on the West Coast. But nuclear plants have not been built at the rate predicted. Slow public acceptance of such plants close to load centers, the attitude of licensing agencies toward earthquake potentialities, and high capital costs have delayed construction of nuclear units. Even so, it is expected that nuclear fuel will account for an ever-increasing portion of total fuel use.

Data on total energy use is graphically displayed on Chart 1 and differs from information presented in the 1963 Advisory Committee Report No. 18.[1] Such differences result, in part, from a change in the area covered as well as from changes in fuel use predictions. Noteworthy is the transposition of coal and nuclear energy sources in the Northwest Subregion during the five-year time lapse between the two studies. Coal, estimated to account for approximately one-third of the thermal generation by 1990 in the first study, is now shown as supplying only about one-fifth of the thermal generation at that time, with nuclear energy supplying most of the balance.

Environmental factors are of steadily increasing concern to the electrical power producing utilities. They may, in some instances, override the normal competitive relationship of fuel supplies. In general though, it is expected that changes in technology, spurred by pressure supplied by environment (air and water pollution) regulations will tend to keep the fuel supplies competitive in the West Region throughout the forecast period.

C. Assumptions

1. U.S. population: up about 1.6% per year, reaching about 285,000,000 by 1990.
2. Gross national product in constant dollars: up about 3.5–4% per year.
3. Defense: at cold-war level.
4. Business Cycles: fluctuations above and below long-run trend, with recessions similar to those after World War II, but no severe depression.
5. Air and thermal pollution controls: increasing at an accelerating rate.
6. Technology: gradual rather than revolutionary changes.
7. Public policy: expected to change in response to enviromental control demands.
8. General price level: up about 1.5 to 2% per year, with fuel prices up slower and with long-run price level changes not being a decisive factor in the choice of fuels.
9. Deviations from these assumptions: will tend to balance out.

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[1] Advisory Committee Report No. 18 on Fuels for Electric Generation in Western United States. Prepared by the West Coast Subcommittee of the Fuels Special Technical Committee, July 1963, published in Part II, National Power Survey, Federal Power Commission 1964.

D. Energy

1. Energy use is a measure of economic progress. In the relatively rapidly growing West (Table 2), the use of energy increased an average of 4.4% per year during the period 1950–1965, compared with about 3.5% for the nation. The difference chiefly results from the more rapid population increase in the West, 3.0% per year as compared to 1.6% for the nation. Due to ever-increasing efficiency in energy use, as well as relatively more rapid increases in the production of services than of goods, energy use tends to rise more slowly than total economic activity. So in constant-valued dollars, the gross national product of the United States tends to rise somewhat faster than energy use. In the West Region, total personal income is approximately proportional to the value of total production and, in constant-valued dollars, such income rose 5.1% per year during the period 1950–1965 compared with 4.4% for energy use.
2. Since population projections can be made to the year 1990 and beyond, with at least some degree of accuracy, and since income and energy use tend to have fairly constant relationships to population and to each other, it is possible to project all three to 1990 as is done in Table 2. Due to a gradually declining percentage rate of population growth, energy use in the West is projected to increase more slowly, declining from a growth rate of 4.8% a year in the 1950–1955 period to 3.4% in the 1985–1990 period. (See Table 2 and Chart 1.) (The recent marked decline in birthrate in the United States must be closely watched. If it signals the beginning of a long-term trend, a number of forecasts will require modification.)
3. Table 3 indicates the major types of energy used in the West. During the 1950's the use of coal declined, while all other major types of energy use increased. In the decades ahead, use of fuel wood will decline slightly while other types of energy will be increasingly used. Coal use in particular should increase rapidly, while nuclear energy use will, expectantly, show the fastest increase percentagewise since it begins essentially from zero in 1960.
4. Table 4 puts all these types of energy on a common basis, in terms of Btu content, and shows that petroleum products accounted for almost half of all energy used during the 1950's. The share of gas increased during that decade and by 1965 exceeded 36%. By 1990, it is expected that gas will have about 26% of the energy market in the West, down from a high of 38% in 1970, while petroleum slips to just over 25%. Hydroelectric generation will decline to about 9%, while coal and nuclear power each rise to 9% and 30%, respectively. But the absolute amount of gas and oil used will continue to grow until perhaps the end of the century. They will merely grow more slowly than the use of coal and nuclear generation.
5. Within this framework of overall energy use, the place of electricity changes considerably. Chart 3 and Table 5 show that in 1950, 20% of the energy used in the West was used as electricity. By 1965, this had risen to 24%. An increase of about this amount was to be expected, since energy use increased 4.4% per year and electric generation 8.4% per year, though the effects of the latter on energy use were partially offset by a 2.2% per year reduction in the heat rate or Btu's required to generate a kwh. (See Chart 2). However, thermal generation increased by 8.8% a year. Whereas it accounted for only 4.4% of total energy use in 1950, it accounted for 10.4% in 1965. These trends are expected to continue. By 1990, total energy use will have more than doubled, electric generation more than quintupled, and thermal generation multiplied almost ten-fold. Electric generation should account for 33% of total energy use by 1975, and thermal generation alone over 20%. By 1990, although the forecasts become less reliable, it is expected that about 52% of the energy used in the West will be used as electricity, with 43% being generated in thermal plants. Thus, fuels for electric generation will account for an ever-increasing percentage of total energy use. Whether the economy can provide this much energy for electric generation, and provide it in a form suitable for this purpose, is a crucial question investigated in

this report. Fortunately, the answer is affirmative.

E. Energy Conversion and Heat Rate

A factor influencing fuel use, i.e., the total fuel mix, is the ever-increasing efficiency of thermal generating plants. From 1950 to 1966, the heat rate, or quantity of thermal energy in terms of British Thermal Units (Btu) required to generate a kilowatt-hour (kwh) of electric energy, decreased from 14,033 to 10,384 in the United States. In the West Region, the reduction in heat rate closely paralled that for the United States, moving from 14,494 Btu in 1950 down to 10,412 Btu in 1965. (Nuclear fuel not included.)

The last column of Table 6 reveals that, for the United States, the percentage reduction in heat rate has been steadily declining since the early 1950's. This decelerated reduction in heat rate has also been experienced in the other areas shown and is projected to continue through 1980.

Further improvements in heat rates in the West Region are expected to parallel the average for the United States. However, long-term projections of heat rates are speculative. For example, the installation of a greater number of large base-loaded nuclear plants than is now anticipated could cause the complementary conventional thermal plants to operate at lower, less efficient, load factors resulting in aggregate heat rates above the current level. On the other hand, installation of more large coal-fired plants than now contemplated (with their relatively low heat rates) could result in aggregate heat rates below those of present conventional plants. A further factor, tending to lower the aggregate heat rate in the West Region is the trend toward sharing, on the part of two or more utilities, the output of a large plant. Thus, the economies of scale can become available, even to small utility companies and fewer small, less efficient plants will be built.

F. Energy Resources Mix for Electric Utility Generation

Table 7 displays the historic and projected sources of energy for electric generation in the three subdivisions of the West Region of the United States.

While hydroelectric generation has satisfied most of the aggregate electric generation requirements of the West Region in the past and is projected to continue to increase in absolute amounts throughout the forecast period, its relative share of the generation has decreased from 78% in 1950 to 57% in 1965. Thermal generation is projected to exceed hydro generation by 1975 and to satisfy an ever-increasing share thereafter. Oil and gas-fired thermal generation, which has represented from about 85% to 95% of the thermal generation from 1950 to 1965, is expected to increase in absolute amount until about 1975 and to decline thereafter—its generation requirement being eroded by more economic, base-loaded coal and nuclear generation. Coal and nuclear generation sources are projected to satisfy the bulk of the increase in generation requirements after 1970.

In the Rocky Mountain Subregion, thermal generation, which represented 75% of the total generation by 1965, changed from predominantly oil and gas-fueled generation in 1950 to approximately an equal mix of oil and gas and coal-fueled generation in 1965. The future increases are projected to be satisfied predominantly by coal-fired generation, much of which will be to satisfy loads in California.

Generation in the Pacific Northwest Subregion in the past has been essentially all hydro. Along with development of the remaining economic hydro sources, increases in requirements are projected to be satisfied by increased nuclear and coal-fired generation sources.

Thermal generation in California, which by 1965 represented about ⅔ of the total generation, in the past has been essentially all oil and gas-fired. Future increases in requirements after 1970 are projected to be satisfied by increased nuclear generation within the state and coal-fired generation located in the Rocky Mountain Region.

Table 7a shows electric generation by industrial establishments for the three regions and Table 7b shows the sum of the electric generation by electric utilities and industrial establishments. Electric generation by industrial establishments has dropped from 7% in 1950 to 3% in 1965 of the total generation; its relative share is expected to continue to decline, representing less than 1% of the total by 1990 even though it is estimated to increase in absolute magnitude by as much as 60%.

Table 8 expresses the thermal generation sources shown in Table 7 in terms of their thermal equivalent in Btu's. Table 9 displays fuels, in terms of their customary units of weight or quantity measure, and

Table 10 shows percent distribution by sources of energy.

G. Natural Gas

Tables 11 through 13 and 13a set forth data on natural gas production, requirements, and consumption in the eleven Western States. New Mexico, California, Wyoming and Colorado are the major producing states with New Mexico exhibiting the greatest increase over the last five years. The overall production increase in the Western States during this period, is less than for the rest of the United States, both absolutely and percentagewise.

The 1963 Advisory Committee Report No. 18[2] on Fuels showed a rapid increase in gas consumption in the Western States, particularly in California and the Rocky Mountain Subregion and this trend is continuing. Although the Northwest and Rocky Mountain Subregions export some gas, chiefly to the West Coast, the overall net supply for the West Region is below demand and it is increasingly dependent upon imports from Texas and Canada, Tables 3 and 12. In 1946, the West Region produced 97% of its gas requirements, including losses and net additions to underground storage; by 1966 production had dropped to 69% of demand, even with substantial increases in production in the West Region during the period.

The portion of the natural gas supply used for electrical generation in the West Region is shown on Tables 13 and 13a and on Chart 4. Use of gas for electrical generation has increased very rapidly since 1946, due largely to use in California, and is continuing to increase at a rate greater than for all other consumption. However, the rate is slowing and it is expected that by 1975 use of gas for electrical generation will level off or even decline in California as a result of pricing and supply factors, resulting in increased use of other fuels—coal, uranium and oil. Use of natural gas for other than electrical power generation is expected to continue to increase, but at a declining rate, throughout the forecast period.

H. Future Availability of Gas

Tables 14–19 provide an analysis of the natural gas supply available to meet the demand indicated by Table 13. Of particular interest is Table 14, showing forecast data on proven natural gas reserves and demand. Canadian exports to the Western States are expected to average about 30% of that country's proven reserves. This source, together with local and imported gas from elsewhere in the United States provides the West Region with its annual requirements. The reserves/requirement ratio shown on Table 14 indicates the life of the reserve at the rate of use shown for given years. This ratio does not take into account two possibly offsetting factors—future additions to the reserves beyond those now conservatively projected and unanticipated changes in future requirements. As a general rule, a ratio of 15 years or more is considered safe whereas below that level a future scarcity of gas may be anticipated by users, and plans should take such a contingency into account. As an example, a thermal electrical generating plant using natural gas should have alternate fuel supplies provided for if the reserves/requirement ratio drops below about 15 years. Since the ratio applies to all requirements, including those receiving preference over electrical generation in the event of a shortage, the 15-year ratio leaves little margin for safety for a gas consuming utility. Table 14 suggests that such will be the case about 1975. The future situation could, of course, be eased by discoveries beyond those now projected.

Estimating future reserves of natural gas is a most difficult undertaking. Upon the uncertainties connected with forecasting the quantity of any natural occurring substance must be added the further complicating factors of cost and price. A reserve is only a reserve if it can be economically produced. Otherwise, it is a resource.

Tables 15 and 16 present data on forecasts of ultimate natural gas supply. Table 15 shows low, medium and high estimates for the United States and Canada. The high estimate for Canadian gas includes potential production from the Northwest territories. Since this region is only slightly explored, the estimate is most speculative.

It should be emphasized that the rate at which the predicted gas supply will become available for use and even the extent to which it will be used is dependent upon a complex interrelationship of economic and technical factors. Prices for natural gas must be adequate to supply exploration incentive. An upper limit, however, is placed on natural gas prices by competitive energy sources. Synthetic gas from low cost coal can be produced for about 40¢ per Mcf. Technology devoted to natural gas production must continue to advance to offset price increases.

[2] Ibid., p. III–3–47.

Natural gas producers, faced with rising drilling costs, want a higher well-head price for gas to provide exploration and development incentive. Mr. Stanley Learned,[3] former president of Phillips Petroleum Company, believes a price of at least 20¢ per Mcf is required to supply adequate incentive. He points out that exploratory drilling in the United States has declined almost 30% since the mid-fifties when additions to the natural gas reserve reached a peak. As a result, new gas discoveries have dropped while demand continues to climb and is estimated to reach about 25 trillion cubic feet by 1975.[4]

In order to offset the decline in new exploration, ways to stimulate additional gas production in known fields are being sought. The most ambitious to date is Project Gasbuggy.[5] A 20 kiloton nuclear explosive was detonated in gas-bearing formations of the Northern San Juan Basin early in 1968. Preliminary indications are that a chimney containing a void of about 2 million cubic feet was created by the explosion. At the time of this writing, production tests are being made but it will not be known for some time whether the objective of the experiment, the economic stimulation of gas recovery, was achieved. Any significant radioactivity will likely be lowered to safe limits by dilution with uncontaminated gas or eliminated by separation. Reservoir engineers estimate recovery of 70% of the original gas in place if the nuclear fracturing experiment is a success. This would mean a substantial increase in gas recovery for the San Juan Basin as well as other areas in the Rocky Mountain Region. If lateral fracturing develops, as hoped, deliverability of natural gas will also be improved over conventional stimulation methods.

The cost of gas, using nuclear stimulation to enhance recovery and deliverability, is not yet known. AEC [6] suggests prices for nuclear explosives used for production operations will range from $350,000 for ten kiloton yields to $600,000 for yields of two megatons. These costs are for the explosive only. Total cost of the Gasbuggy Project is about $3,000,000, excluding cost of the explosive. Production operations should be less costly than the experiment. If actual recovery and deliverability come up to expectations and production costs can be reduced by using, for example, smaller diameter emplacement holes (Experimental emplacement hole was sized for 15-inch I.D. casing) the cost of natural gas produced is expected to be competitive.

Referring to the medium supply estimate shown in Table 15 and projecting the gradually declining rate of increase of use shown on Table 13, it follows that the supply of available natural gas for the West Region will be depleted by about the year 2020. As gas supplies become more limited, lowered deliverability may require a stretch-out of the remaining supply for high priority users and a curtailment of low-preference use. Thus, use by utilities could be reduced at a rate greater than that shown on the Table.

Synthetic gas from coal can be produced for about 40¢ per million Btu, depending upon cost of coal. Four methods of producing pipeline gas from coal are:

1. CO_2 Accepter Process—Consolidation Coal Co.
2. Coal Hydrogasification—Institute of Gas Technology.
3. Coal Gasification Process—M. W. Kellogg Co.
4. Two-Stage Extrained Gasification—Bituminous Coal Research, Inc.

All of these processes show promise of producing gas in the price range of 38–55¢ per million Btu. With improvements that can reasonably be expected to be made in the various gas-from-coal processes, large commercial facilities operating on low cost coal ($1.50 per ton) could achieve costs in the 35–40¢ range by the mid-seventies. At this point, synthetic gas can begin to displace natural gas.

Table 16 shows the effect of deducting the estimated requirements from the medium estimate of natural gas supply. Around 1985, projected use will overtake estimated additions to the reserve and the proved recoverable reserves of gas will decline thereafter. Higher or lower estimates would shift the dates for these changes, but the pattern remains the same. It is expected that before the end of the century, reserves will decline and natural gas supplies will become tighter.

Tables 17–19 contain background data on past changes in the proved recoverable reserves, which during the post World War II years changed little in the West Region. Reserves reached a peak in the

[3] Stanley Learned—Address Before the Executive Club, Chicago, Illinois, March 11, 1966.

[4] Future Requirements Agency, Denver Research Institute. Future Natural Gas Requirements of the United States. Vol. 2, June 1967.

[5] Joint Operation—El Paso Natural Gas Co., U.S. Atomic Energy Commission, U.S. Bureau of Mines and the Lawrence Radiation Laboratory.

[6] Project Gasbuggy

mid-fifties and have declined gradually since that time. New discoveries added 10.7 trillion cubic feet to the reserve in the period 1947–66 and revisions and extensions of figures for previously discovered fields added 29.1 trillion, making a total of 39.8 trillion cubic feet. Production was 28.6 trillion cubic feet, making an increase of 11.2 trillion cubic feet in the reserve in the eleven states. This is 2.6 trillion cubic feet less than the increase for only ten states shown for the period 1947–61 published in Report No. 18.[7] While withdrawals during 1947–66 were 2.7 times new discoveries, the amounts recorded as new discoveries must be augmented by later revisions and extensions before it is clear whether or not gas is being found as fast as it is being consumed. Unfortunately, the proportion of the revisions and extensions allocable to new discoveries for particular years is not available.

I. Fuel Oil

1. Table 20 summarizes the historical supply and demand for conventional domestic cracked residual fuel oil, which contains from 1.5 to 2.0% sulfur. The highest yields by far have been in District V, which is made up of the seven Western States of California, Oregon, Washington, Arizona, Nevada, Alaska and Hawaii. District V accounts for about 80% of the eleven Western States' refinery capacity and California accounts for 85% of District V refinery capacity. Air pollution control regulations have limited the market for conventional cracked residual fuel oil, resulting in refiners modifying their processing systems to decrease the yield of such oil and to increase the yield of the more valuable lighter products per barrel of crude processed. The quantity of crude oil refined in District V has been increasing at about 2.75% a year. However, the expected large decline in residual yield percentage indicates residual oil production of approximately 95 million barrels in 1970 and 50 million barrels by 1975.

   Two major electric generating utilities with combined fuel oil requirements equal to nearly 70% of the electric generation residual fuel oil requirements shown on Table 21, operate in Southern California. Air pollution control regulations in that area require the utilities to use gas fuel whenever it is available. However, the gas supply is interruptible and substantial quantities of fuel oil must be used. Historically, most of the oil requirement has been conventional residual fuel oil supplied by California refiners. Domestic residual fuel oil contains approximately 2% sulfur. The Southern California utilities are switching, therefore, from such oil to a low sulfur product of less than 0.5% sulfur in cooperation with the air pollution control authorities. Complete substitution of such low sulfur oil for gas will meet standards established by the Air Pollution Control District, County of Los Angeles.
2. Table 21 shows fuel oil requirements for electric generation in the eleven Western States. The requirements for the projected years are expected to be increasingly met by low sulfur fuel oil containing less than 0.5% sulfur by weight. If the Hawaiian Electric Company oil requirement, which is also served by District V refiners, is added, the low sulfur oil component would be increased by about 5 million barrels in 1970. Consideration of trends in Tables 20 and 21 indicate that in the near future it will be necessary to import fuel oil, particularly low sulfur, to meet the electric utility demand for oil.
3. Table 22 illustrates how, oil-wise, the eleven Western States are becoming less self-sufficient and are expected to become more reliant on imported crude oil; the net import of crude petroleum and petroleum products amounted to about 1% of requirements in 1965. Residual fuel oil production for the eleven Western States is reliant on imports to a similar degree. The rising Alaskan production and the potential off-shore development in the Santa Barbara Channel Islands area of California, together with the trend of conversion of residual fuel oil to more valuable products could have the effect of reducing the overall requirement for imported crude oil. However, because sufficient supplies of low sulfur oil are not currently available from domestic sources, the electric generating utilities must rely on the importation of low sulfur oil. The percentage of fuel oil from foreign sources used

[7] Ibid., p. III-3-47.

for electric generation in California, the principal oil burning state, is estimated at about 67% by 1970.

4. Table 23 shows that estimated proved reserves of crude oil and natural gas liquids in the eleven Western States are rising slowly. Tables 24–25 indicate that during 1947–1966 new discoveries added about 1.5 billion barrels to reserves, and revisions and extensions of previously discovered fields added 14.5 billion barrels making total additions 16.0 billion barrels. Withdrawals totaled 12.7 billion barrels, so reserves rose 3.3 billion barrels.
5. Because the supply of low sulfur crude oil in the Western United States is limited, although Alaska production is increasing, the Southern California utilities must look to importing low sulfur fuel oil or low sulfur crude oil to comply with air pollution regulations. Such oil is available from Indonesia, Liberia, South America and North Africa. Low sulfur oil produced in the Gulf Coast area of the United States is not competitive with oil from these regions. In response to the demand, and subsequent to revisions in the Oil Import Administration's regulations allowing importation of low sulfur oils into District V destined for use in mitigating air pollution problems, several major oil companies have contracted to produce and sell considerable volumes of low sulfur, low ash fuel oil to several large electric utilities in Southern California.
6. Low sulfur, synthetic fuels produced from coal, oil shale or tar sands will probably supply a portion of this increasing requirement in the future. The timing depends upon the interaction of technological and economic factors including the future availability and price of imported foreign low sulfur crude oil. Among these sources, synthetic crude oil/fuel oil produced from coal, and coal extract (which can be in either the solid or liquid form) are of special significance because the estimated recoverable reserves of coal are so large, many times the free world's proved reserves of petroleum. Furthermore, many of these coal reserves (and necessarily the contiguous processing centers which would be constructed) are in reasonable proximity to the western refining centers and markets for the fuel.

   Synthetic fuel from coal may have an economic advantage over fuel produced from oil shale or even tar sands. Most processes now being investigated in the United States yield a fluid fraction and a solid residue or char. Since electrical generating facilities can burn char, combining the plants into an integral operation producing synthetic fuels and electric power could offer economic incentives.
7. It is anticipated that desulfurization of domestic residual fuel oil, although technically feasible, will not be economically attractive in the foreseeable future. Current estimates indicate that this process would add about $1.00 per barrel to the cost of the fuel oil to lower the sulfur content to 0.5% by weight without any accompanying reduction in ash content.[8] Low sulfur imported crudes currently available yield fuel oils with considerably lower sulfur content and far lower ash content at a lower price premium.
8. Another approach to meeting air pollution regulations pertaining to the burning of high sulfur residual fuel oils for electric generation is to remove the potential pollutants from the power plant stack emissions before release to the atmosphere.

   A number of stack gas treatment processes have been developed beyond the laboratory stage and have received serious developmental efforts in pilot plant tests. These processes, typically, can remove about 90% of the sulfur present in the stack gases. The sulfur compounds are oxidized and/or absorbed by materials or chemicals injected into the gases and are then removed by precipitation or wet scrubbing.

   The additional plant equipment required by these processes would require large capital investments, and, because electric generating utilities typically satisfy only approximately 10 to 25 percent of their annual oil and gas fuel requirements with fuel oil, the stack gas treatment facilities would operate at a proportionately low

[8] Oil & Gas Journal, May 22, 1967—At 0.5% sulfur, cost is about $1.00/Bbl.

annual capacity factor effectively adding from 50 to over 200 percent to the cost of each barrel of high sulfur residual fuel oil burned, depending upon the process employed. For example, studies indicate the application of the "Welman-Lord" stack gas treatment process, which removes approximately 90% of the SO_2 present in power plant stack gases, to a power plant operating at a 66 percent annual capacity factor, would add the equivalent of only $0.25 per barrel of fuel oil burned if 100 percent of the plant's fuel requirements were satisfied with fuel oil, but would add approximately $1.00 per barrel to the cost of fuel oil burned if only 20 percent of the fuel requirement were satisfied with fuel oil. These costs include a credit for saleable by-products recovered in the process.

J. Coal

Coal production in the West Region, after a long period of decline, appears to have bottomed and is beginning an upswing that is expected to continue throughout the forecast period. (See Table 26). Use for electrical power generation will account for most of this increase in production, especially during the early 1970's. After 1975, use of high volatile bituminous coal for production of synthetic oil and gas is expected to consume significant quantities.

The West Region contains about a quarter of the total United States reserve of coal. Only five of the eleven West Region states contain important deposits (Table 29). The estimated reserve figures shown on Table 28 will change considerably by the early 1970's. Detailed evaluation of western coal deposits was just getting well under way in 1966, and much more accurate data on recoverable coal and methods of mining will become available in the near future.

Presently, the coal deposits of Wyoming, Montana, Arizona and New Mexico appear to offer the greatest potential for strip mining. Generally speaking, the strippable deposits are slightly lower rank than the more deeply buried coal seams in Utah. Some of the thickest seams occur in the Powder River Basin of Wyoming and Montana, locally attaining thicknesses of 100 feet. Much of this coal is strippable, particularly along the periphery of the gently dipping formations, as at Wyodak, Wyoming, near the eastern edge of the coal deposits. In general, the coal seams occur at increasing depth toward the central portion of the basin and recovery will require underground mining methods. It is in the center of this basin that Project Thunderbird, a proposal for in-situ gasification of coal by use of nuclear device, is to be located.

Huge reserves of coal are available in the West Region for electrical power generation. Several billion tons can be recovered by very low cost stripping methods. Two factors, however, affect the economics of coal-fired plants located on or adjacent to a coal reserve. These are (a) the availability of water (See Section Q), and (b) long distances from major load centers.

Apparently these factors—transmission distances, and water availability—have brought about a major change in the future plans of the utilities in the Northwest Subregion. The 1963 report[9] projected coal as the major source of new energy to the year 2000. Five years later, the situation is reversed, with nuclear plants accounting for the bulk of new power in that area. Adequate cooling water at a number of sites having relatively short transmission distances to load centers give nuclear stations a competitive edge. However, rising costs for nuclear plants may reduce the advantage, especially if coal can continue to reduce production costs.

Steam plants located adjacent to strip coal in the West Region have the lowest fuel cost of any in the country. Delivered cost of coal at the Dave Johnson Generating Station, Glenrock, Wyoming, is about 14 cents per million Btu's. At Castlegate, in Utah, a mine-mouth plant using coal from an underground mine, receives fuel at 18.2 cents per million Btu's. The two are not directly comparable since the coal quality differs somewhat, but they do provide an idea of price range. A large mine-mouth facility near Farmington, New Mexico will, by 1970, be consuming about 7 million tons of coal annually and even though the coal is low quality (19,000,000 Btu's or less per ton and over 20% ash) delivered cost to the power plant is about 12 cents per million Btu's. A large underground mine would be expected to deliver coal to a mine-mouth power plant for about 14–15 cents per million Btu's.

To be noted in the case of recently developed mines and potential mines devoted to power plant fuel supply for long-time periods (10–30 years), the mining costs would be expected to be minimal. Such mines are operating with the latest mining

[9] Ibid., p. III–3–47.

machines and mining programs. Productivity, therefore, is far greater than the national average. Surface mining equipment has grown in size and reliability without any appreciable addition to, and in many cases, a reduction of, size of crews needed to operate and maintain it. Modern strip mines can produce coal at a rate of over 100 tons per man-shift and as new mines are developed or older mines updated, this figure will increase.

Underground recovery of coal has shown even more remarkable improvement relative to its early rates of productivity. Under favorable conditions, underground mines can approach production rates as great as many strip mines—up to 50 tons or more per man-shift. Automation underground can be expected to allow production rates in excess of 100 tons per man-shift.

K. Nuclear Generation

As of mid-1968 two reactors are, in addition to AEC's Hanford Plant, operational in the West Region. These are the Humboldt Bay, 70-megawatt plant owned by Pacific Gas & Electric Company and the San Onofre 450-megawatt plant owned by Southern California Edison Company and San Diego Gas & Electric Company. Others are planned and possibly 4 or 5 reactors could be in operation by the mid-1970's. At least three of these would be in California.

The switch to nuclear power in the West Region has been slow, even in California, where it was expected that the change-over would be rapid due to air pollution controls and domestic-fossil fuel prices. However, a number of factors control the time and place of competitive nuclear power. The following are among the more important:

a. Capital and fuel cost trends of fossil-fueled plants;
b. Capital and fuel cost trends of nuclear plants;
c. The capability of electric utility systems to operate nuclear plans at a high average capacity factor;
d. The ability of electric utility systems to use large generating units—500 mwe or larger;
e. The development of advanced thermal and fast breeder reactors;
f. The use of plutonium as a recycle fuel;
g. The economics associated with private ownership of nuclear materials and processing facilities;
h. Public acceptance of nuclear stations;
i. Environmental regulations.

The cost factor is a common ingredient in all the items listed above. In the final analysis, the fuels will be considered along with their environment control costs, and of those acceptable, the most competitive will be used.

It is expected that within the forecast period, nuclear energy will become an important source of electric power in the West Region, especially in the coastal states. However, projections such as those in Tables 7–10 become rather uncertain beyond about five years.

The kilowatt-hour costs of Pacific Gas & Electric Company's Humboldt Bay nuclear plant at Eureka, California, are reported to be slightly below the cost of fossil fuel at that rather remote locality. The cost is higher than that of fossil-fueled plants in the vicinity of San Francisco.

It is expected that the 450 mwe San Onofre nuclear station at San Clemente, California, will have kilowatt-hour cost close to conventional steam plants, but at the time of this writing, the plant has not been on stream long enough to provide reliable data.

Moderate reductions in nuclear costs, modest increases in fossil fuel costs, or environmental pollution control of fossil-fueled plants could make nuclear power competitive over a large portion of the West.

Capital costs for nuclear plants began climbing in 1967 reversing a trend of declining costs. Price of nuclear fuel has changed little, with rising costs of uranium ore offset in part by improved reactor performance and lower enrichment costs.

The 1963 Advisory Committee Report No. 18 [10] suggested that most of the additions to generating capacity in Northern and Central California were expected to be nuclear in the early 1970's. With costs trending upward, construction of nuclear plants could be postponed. Whether this rising cost trend will continue is uncertain. If it does, it will be about 1985 before California has half of its generating capacity in nuclear installations and it would be long after that year before the West Region's capacity becomes 50% nuclear.

Existing and prospective hydro-electric generation in the Northwest Subregion and large reserves of coal and natural gas in many of the states of the

[10] Ibid., p. III–3–47.

West Region will compete strongly with nuclear fuel for electric power generation.

L. Nuclear Generation Costs

Capital cost per kilowatt was about $130 for conventional fossil-fueled plants in 1960–1962. Nuclear plant costs dropped from about $350 in the late-fifties to an average cost of about $160 per kilowatt for units in the 500 mwe or larger range in the mid-sixties.

In 1966 TVA announced a decision to construct a large two-unit nuclear plant located at Brown's Ferry in close proximity to coal fields. Cost per kilowatt was $116 with a total energy cost of 2.39 mills per kilowatt-hour. In comparison, a coal-fired plant of about the same capacity cost $117 per kilowatt with an energy cost of 2.90 mills per kilowatt-hour.[11] This was the first time that capital costs of nuclear plants were shown to be on a fully competitive basis with fossil-fueled plants.

These costs, however, do not seem to have been a valid indication of future price trends in the nuclear industry. When TVA announced in 1967 that a third nuclear unit would be built at Brown's Ferry, it was noted that nuclear costs had gone up and no longer held a competitive advantage over coal in that area.

Presently, costs for nuclear plants in the West Region fall in the range of $150 to $200 per kilowatt.

The unsettled state of nuclear power plant costs may lead to a slow-down in the rate of nuclear growth in the West Region, particularly in areas of low cost fossil fuels. However, similar cost uncertainties also apply to some extent to conventional plants.

There is not yet sufficient experience to establish any firm basis for projecting nuclear costs. The estimated cost comparisons between nuclear and conventional plants persuaded utilities to place an impressive number of orders for nuclear units. The long-term validity of these costs is not certain, especially now that manufacturers are raising prices. However for individual plants, once major equipment is committed with manufacturers, a large portion of the plant costs are known or predictable.

Combination nuclear plants, conceived to perform more than one function, are generally considered a way of obtaining, principally through economies of scale, low cost electrical energy. A combination electrical generation and water desalting plant such as the proposed Bolsa Island installation in Southern California is an example. Plants of this type make use of very large reactors with the heat output used to drive turbines and also elevate the temperature of marine water. Whether such facilities will actually produce electrical power at costs lower than a single purpose plant is not yet clear. Nevertheless, in populated regions where the need for water is an important factor, such dual installations probably can deliver water at a lower cost than would otherwise be the case using a single purpose desalting plant. The water purification portion can be considered an incremental part of the electrical generation facility and cost, therefore, less affected by overall price changes.

Prices of uranium ore concentrates (75% or more U_3O_8) currently are about $7.00–$8.00 per pound, and little change is expected well into the 1970's. Should a brief period of oversupply result from the present extensive exploration effort, this price range (possibly with fluctuations below the range) may be extended beyond the mid-seventies.

Conversion costs (U_3O_8 to UF_6) are subject to labor and material escalation charges, and are expected to climb at about 1½ to 2% per year. Surcharges, applied to U_3O_8 concentrates that are not "standard" could further increase conversion costs which were just over $1.00 per pound of contained uranium in 1967.

Enrichment charges presently are fixed by AEC at $26.00 per unit of separative work. This unit is the amount of energy required by the diffusion plant to enrich the U–235 content of natural uranium * to a given level. For example, to produce one kilogram of uranium enriched to 3% by weight in U–235, 4.31 units of separative work are required on 5.5 kilograms of natural uranium; the remaining "tails" contain 0.2% U–235. This operation is the only remaining step in the fuel cycle still under Government control.

Fuel fabrication costs have declined substantially since the mid-fifties. This has been the result of a degree of standardization, increased production volume, and increased use of automation in the manufacturing processes. However, labor cost escalation will be a major factor in fabrication cost trends. Fuel fabrication (including fixed charges) accounts for about 40% of the fuel cycle costs for

[11] TVA-Comparison of Coal-fired and Nuclear Power Plants for the TVA System—June 1966.

*Uranium as it occurs in nature contains 0.71% U–235 99.28% U–238 and 0.01% U–234.

plants now in operation, and would account for about 30% for the larger plants expected to begin operation in the 1970's.

To summarize, the cost of the fuel cycle component for nuclear plants has declined markedly since the mid-fifties. For planned large reactors (1000 mwe) the estimated cost breakdown for the fuel cycle in the 1970's is approximately as follows:

	First core	Levelized cost, succeeding cores
Raw fuel (U_3O_8) at $7.00/lb	0. 40 mills/kwh	0. 49 mills/kwh
Conversion and enrichment	. 48	. 52
Fabrication	. 55	. 35
Reprocessing and shipping	. 25	. 20
Gross, direct fuel costs	1. 68	1. 56
Less: Spent uranium credit	–. 15	–. 14
Plutonium credit	–. 28	–. 26
Total Credits	–. 43	–. 40
Net direct fuel costs	1. 25	1. 16
Fixed charges and interest	. 40	. 39
Total Fuel Cost	1. 65	1. 55

The nuclear fuel cost is below that of conventional fuel on the West Coast, but escalation of manufacturing and construction costs suggest that nuclear plants may not yet have any significant competitive advantage over other fuels. While overall plant economics are basic, decisions on particular plants will also be influenced greatly by environmental considerations.

Faced with expected rising fuel costs in the late 1970's, there is ample incentive to develop advanced converter and breeder reactors as soon as possible. AEC and industry are continuing efforts on both concepts. The advanced converter reactor is considered an intermediate step to breeders. Advanced converter reactors, such as the HTGR, appear to be emerging as a commercial possibility during the forecast period. These reactors would not only use less fuel themselves but also, as a result of their low incremental fuel cost, would tend to reduce the capacity factor and fuel use of interconnected older, light-water reactors. The fuel savings in ten years could amount to several billion dollars nationwide. An advantage particularly significant in the West is the low cooling water requirement of advanced converters—little more than for conventional thermal plants, compared with 75% more for present light-water reactors.

Research on breeder concepts is being accelerated, by both Government as well as private industry. AEC has awarded contracts to Atomics International, Babcock & Wilcox, Combustion Engineering, General Electric and Westinghouse. If progress is satisfactory, there will be less need for advanced converter reactors during the interim. It can reasonably be expected that a demonstration breeder reactor can be developed by 1980 and that commercial units could begin to go on stream before 1990. Breeders will, however, have little impact on the demand for uranium ore within the forecast period of this report. With successful development of a practical breeder reactor, the nuclear industry will have attained an important objective, and stable long-term fuel costs will become less elusive than they are at present. Inflationary factors and political control of raw materials will still govern relative economics to an important extent.

M. Nuclear Fuel Reserves

Uranium

The uranium supply situation can be briefly summarized as follows:

1. Known domestic reasonably assured reserves are not large, probably about 150,000 tons of U_3O_8 in the $8.00/lb. or less price range.
2. The potential for finding substantial reserves of uranium is considered to be good. Estimates by the AEC indicate a reserve of over 650,000 tons of U_3O_8 in the $10.00/lb. or less price range. Table 34 includes the AEC

estimate as of January 1968 for reserves in the reasonably assured category, as well as for geologically expectable reserves in three price ranges.

3. Continuing escalation could drive the price of U_3O_8 concentrates to over $10.00/lb. in the late 1980's.
4. An extensive exploration effort began in early 1967; however, it will be 1969–1970 before results of this work begin to be known.
5. The uranium supply situation in 1970–1972 could, if forecasts of nuclear power generation actually attain the high level forecast of 170,000 MW in 1980, become tight. However, should actual capacity lag behind this figure by a few years, supply of U_3O_8 concentrates should be adequate and as new mines and mills come on stream in the early 1970's a surplus may develop. This will be especially true if renewed development work in known districts proves up a greater amount of reserves than the conservative estimate made by the AEC. Furthemore, the revised price schedule set by the AEC of $26.00 per separative work unit with a tails assay of 0.2% U-235, effective January 1, 1969 will reduce requirements for natural uranium by about 8%. If a shortage of uranium concentrates occurs, AEC expects, subject to the conditions set forth in its Uranium Supply Policies, to make nuclear material available from a 50,000 ton (U_3O_8) stockpile.

The uranium boom of the fifties, triggered by substantial Government subsidies, paid off handsomely and by 1958 the AEC took steps to retard the production rate of uranium. In 1961 production reached its peak in the United States and then began to decline in response to AEC purchase programs. Thus, at the peak of discovery and production, the uranium industry was curtailed by lack of a market.

In 1967 in response to a reviving market provided largely by utility companies rather than Government, a second uranium exploration and development effort began. In the fifties, individuals and companies alike joined in the search for radioactive material and the bulk of the surface exposures are presumed to have been found. The 1967 exploration boom is more systematic and includes companies knowledgeable in uranium exploration. New deposits will be found on the basis of geological and geophysical data, coupled with extensive exploratory drilling, and such activities require large expenditures. (AEC estimates an expenditure of $315,000,000 in the four-year period 1968-1971).

A similar situation is developing outside the United States. Known areas are being re-evaluated and new districts are being sought. Uranium, once considered to be a rare, and useless element, probably has become the most thoroughly studied substance in the earth's crust. At the time of its discovery in 1789 in a mineral called pitchblende, it was merely a chemical oddity. It was not until the early 1900's that uranium was considered to be the parent of a series of radioactive elements. It required World War II to provide the stimulus needed for an intensive study of uranium—its mineralogy, geologic occurrence, geochemistry and nuclear properties. All this because in 1939 it was discovered that an atom of uranium could be made to split, or fission, releasing huge amounts of heat and radiation energy.

In the mid-fifties, the search for uranium began and now it is recognized that uranium is not as rare as was first thought. Pitchblende, for years thought by mineralogists to be the principal mineral of uranium, is now considered to be only a variety of the mineral uranite—one of about 185 mineral species in which uranium is a major constituent.

Uranium deposits have been found on every continent.

Presently, the known important uranium provinces (large indefinitely bound areas containing uranium-bearing rocks) are:

1. Canadian Shield—especially Elliot Lake region, Ontario, Canada (Sedimentary)
2. Colorado Plateau, Western United States (Sedimentary)
3. South Africa (Product of gold mining operations)
4. Eastern Brazil (Vein deposits chiefly)
5. Australia (Vein deposits in the Northern Territory and Queensland)

6. USSR (Not well known—probably sedimentary deposits similar to Colorado Plateau)

In the areas above, deposits are generally high grade or can otherwise compete in a price range of \$7.00–\$10.00 per pound of U_3O_8. In addition to such relatively high grade deposits (uranium content—0.1–0.5%, or 2–10 pounds per ton of rock), extensive low grade occurrences in organic shale, phosphate rock, lignite, and granite rocks are known, but these are high cost resources not expected to be economic in the foreseeable future.

Thorium

The element thorium, like uranium, is transmutable, by neutron capture, to U–233, a fissionable isotope. Thorium will likely become an important nuclear raw material for reactors that convert Th–232 to U–233. The U–233 would then be used as fuel in reactor cores.

Thorium is somewhat more widespread throughout the earth's crust than is uranium and is found principally in three minerals—thorite, thorianite, and monazite. The thorium minerals are resistant to weathering and commonly occur as placer deposits in beach and river sands. Monazite particularly is recovered from such deposits. The primary habitat of the thorium minerals is in vein deposits or as disseminations in igneous rocks, i.e. granite.

Reserves in the United States are estimated at about 100,000 tons of ThO_2, but little effort has been made to explore for the material. It is to be expected that this figure can be increased many-fold should thorium demand become great. Canada and India are the major suppliers of thorium for the world market. Placer deposits in India have been worked for many years. Estimate of reserves in India is 250,000 tons of ThO_2 and in Canada, 200,000 tons of ThO_2.

Below is a breakdown of thorium resources in the United States.[12]

Price range per pound ThO_2	Reasonably assured reserves (thousands short tons ThO_2)	Estimated total resources (thousands short tons ThO_2)
Under \$10.00	100	400
\$10 to \$30	100	200
Over \$30.00	1, 000, 000	3, 000, 000

N. Uncommon Energy Sources and Potential Technological Changes

Some of the uncommon sources of energy for thermal electric generation that have been considered or used in the Western Region are: liquefied natural gas (LNG), sewage gases, compressed or processed refuse, low sulfur coal extract and char and/or gas from coal. LNG is currently in limited use principally as direct conversion energy, i.e., natural gas for peaking purposes although it is now planned for electric generation in Japan. Sewage treatment digester gas is available from sanitation plants in some metropolitan areas, but the small quantities and low heating value make this energy source insignificant. For example, a typical large capacity sewage treatment plant produces about 2 million cubic feet of 600 Btu/cf gas per day from the sewage from 1 million people. Translated into electrical energy, this would provide fuel for about 5 megawatts of generation, or about ½% of the nominal total demand of 1000 MW per million population. Wood waste has a heat content of about 9000 Btu/lb. It is used only to a limited extent because the supply is dwindling, as such waste is being upgraded into more valuable products.

The huge volumes of combustible waste in the form of rubbish and refuse which is generated each day in our society could be processed for use as boiler fuel, thus accomplishing a dual purpose, refuse disposal and thermal generation. Such processes are in operation in Europe, elsewhere in the U.S. and are expected soon in certain West Region communities. An alternative to direct firing of rubbish as boiler fuel would be disposal by incineration in closed retorts which would produce a 650 Btu/cu. ft. combustible gas, half of which would be available for boiler fuel. Refuse has a heat content in the range of 4000–5000 Btu/lb. and where available

[12] Modified from Mineral Facts and Problems—U.S. Bureau of Mines, Bulletin 630. 1965.

in large quantities near the electric power market it may be suitable as a fuel for supplementary power generation.

Use of refuse by electrical power utilities will likely be as a service to large metropolitan centers rather than as a competitive fuel for thermal generation. Although in the aggregate large cities produce a vast amount of burnable waste (Los Angeles, San Francisco, Seattle, San Diego, Portland, Phoenix, Denver and Salt Lake City and their contiguous metropolitan areas combined, produce about 37,000 tons per day), individual population centers provide only a small fraction of the energy demand. For example, only about 100 megawatts per million population could be fueled or about 10% of the nominal energy demand of 1000 megawatts per million population; the 37,000 tons of refuse per day from these western load centers could fuel only about 1700 megawatts compared to a total energy demand of about 17,000 megawatts. Waste burning installations would require a subsidy—either in the form of a charge to the City for disposal of waste or a fee charged to individuals and organizations for collection of waste.

Low sulfur coal extract is produced by mild hydrogenation of coal in the presence of a solvent at a temperature which causes the coal to depolymerize. Ash and sulfur content is lowered in the process. The extract is solid at room temperature, but when heated to 500°–600° F. becomes a liquid that can be fired like regular fuel oil. The extract, being solid, can be transported in slurry form. The char by-product of such processes is suitable for boiler fuel. Combustible gas is another product of coal liquefaction.

Several uncommon energy conversion processes are of interest, although unlikely to become of any consequence during the period covered by this study as an influence upon the fuel mix. The magnetohydrodynamic (MHD) generator, one such potentially important conversion process, utilizes a high-speed plasma (a very hot gas which is an electrical conductor) which functions as the armature of the generator, developing a voltage by the motion of the plasma streaming through a magnetic field. If the voltage is connected across an electrical load, energy is delivered directly from the plasma to the load. Alternate fuels adequate for MHD generation could include the combustion products of coal seeded with an ionizable impurity such as potassium salt.

In addition to MHD generation, two other direct conversion methods of generating electricity are the thermoelectric generator which relies upon the thermocouple effect between dissimilar metals and the thermionic converter which operates as a result of evaporation of electrons from a heated surface of one electrode which is closely spaced with another electrode held at a lower temperature. Thermoelectric generators are in use for powering telephone equipment in locations where there is no readily available commercial power, and thermionic converters are used in space power systems. As usually conceived, both methods would use gaseous fuels. Efficiencies and cost levels achieved are unpromising for central station power production.

Fuel cells utilizing natural gas, gasoline, diesel oil and other readily available hydrocarbon fuels might serve as residential power plants, portable power units and vehicle power plants, but their economics are presently adversely affected by high investment-use ratios. It is estimated that costs on the order of \$20–\$60 per kw, or \$200–\$400 per kw with energy storage, must be attained to compete with electric utility service to the residential market. A breakthrough in fuel cell development making the "black box" economically practical for installation in homes could increase the use of natural gas, the most convenient and logical home fuel, while temporarily reducing, or slowing the rate of increase, of gas use at central generating plants. Such a widespread switch to natural gas would eventually present a supply problem. Other sources of gas would have to be developed, such as gas from coal. Natural economic forces would compel an upward trend in gas prices; this coupled with a continued downward trend in central station electric energy costs combined with load diversity, would be expected to limit any trend toward the gas-fueled residential fuel cell.

Direct conversion of solar energy involves use of a source with too low an energy density for economical power generation. Most other uncommon energy sources are similarly limited.

The present report conservatively, and for the most part only indirectly, considers the effects of future technological changes. Most such changes are assumed to be sufficiently taken into account in the projections and discussion of total energy use, total electric generation, nuclear generation, the heat rate, coal production and transportation, refinery yields of residual fuel oil, the transportation of energy, etc. Many potential, but not assured,

technological changes are disregarded in this study on one or more of the following grounds:

1. The impact on fuel requirements would be relatively minor, at least prior to the year 1990. For example, tidal power and direct solar power.
2. The resulting changes in fuel requirements would merely speed up or slow down, rather than basically alter, the changes in fuel use projected in this report, so that plans made on the basis of this report would not have to be altered so much as delayed or moved forward. For example, magnetohydrodynamic generation might obtain additional kwh per million Btu of a particular fuel and so somewhat curtail fuel demand.
3. The impact on fuel requirements would be so great that a new analysis would be required at the time, and any projections made now would be quite unrealistic regarding future changes. For example, ultra low cost power from nuclear fusion.

Use of coal in the West could increase significantly with development of more economic dry cooling tower systems together with compensatory coal prices. This system consists of a closed water circuit containing air/water heat exchangers which dissipate the heat to the atmosphere with no water lost by evaporation. Since no makeup water is required, this system has great potential in the water-deficient West and would result in increased consumption of coal at the mine mouth without regard to water availability. However, present economics indicate dry cooling costs a premium of $17-$21 per kw.[13] Even at a high use of generating capacity this would increase the cost of energy by 0.3–0.4 mills per kwh.

New technology in railroad electrification will have an impact upon fuel utilization for electric generation within the next few years when the San Francisco Bay Area Rapid District commuter facilities are completed and central station nuclear, gas and oil-fired electric generating plants supplant some use of gasoline-fueled public transportation and private motor vehicles.

Two other metropolitan area projects in the Puget Sound and Los Angeles areas may be built in the not too distant future, causing some additional changes in the industrial fuel mix.

[13] Rossie and Trommershausen—Witnesses R. W. Beck and Associates "Power Cost Study for Fuel Research Council, Inc., Wahington, D.C." Federal Power Commission Docket CP63–204, et al, Exhibit 220.

Electrification of segments of mainline railroads may have as much impact by 1990 upon raw fuel utilization as any pending technological developments. Railroads could increase utilization of trackage and offset the continuing increase in costs of maintenance and operation with present equipment. Combinations of geography, load factor and a particular railroad's needs for replacement equipment will undoubtedly dictate the rate of change to electrification. It is evident that the potential exists for some major conversions within the time period of this study. The Edison Electric Institute is conducting an industry-wide survey at the present time of the potentials in railroad electrification, and several railroads in the West are reported to have made or are making serious studies of electrification.

In 1966, approximately 26 million barrels of oil fuel were used for locomotives in the West Region. While there is a difference in overall fuel utilization efficiency of some consequence, it is believed that the primary impact of conversion to central station generation for railroad locomotion would be the substitution of coal and nuclear generation for the use of fuel oil. Because many of the western railroads cross large coal deposits, it is obvious that coal should get a large share of this business. However, no estimate of this potential was set forth in the most recent comprehensive publicly-financed investigation of the potential market for far western coal and lignite. So experts may not agree that we will see in the near future a return to the starting point in the cycle of railroad fuel utilization.

O. Fuel Prices

While it can be said that fuel prices influence the selection of fuels for electric generation, in certain areas in the Western United States, such as Southern California, the electric generating utilities are compelled to use higher priced low sulfur, low ash fuels (See Section I) when available and regardless of cost because of air pollution regulations. Tables 36–40 summarize past data on fuel prices.

From 1946 through 1965 well-head prices for natural gas in the United States have increased at an average annual rate of 5.9% compounded. However, the rate of increase is declining and for the ten-year period 1955–1965 averaged 4.1% and declined even further to about 2.2% for the five-year period 1960–1965. In New Mexico and California, which togther account for more than 75% of total gas produced in the eleven Western States, natural gas

prices at the well have increased at an average annual rate of 2.0% and 3.0% compounded respectively, over the five-year period 1960–1965. Although the rate of increase is declining, a minimum increase in well-head prices of about 1% per year might be expected over the long term to encourage exploration and development of new supplies.

Table 37 presents data on average prices for natural gas for industrial use (including electric generation) and Table 38 shows the gas costs reported by electric generation utilities. Gas prices increased substantially during the period 1950–1961; however, this trend was reversed in 1962, as a result of the settlement of rate proceedings of gas pipeline companies serving the western area and the lower incremental costs of new supplies. However, the slight downward trend in gas prices appears to have leveled off and, as the demand for gas increases and supplies decrease; an upward price trend is expected, even though the recent Permian Basin decision of the Federal Power Commission resulted in a slight price reduction in that area. The California electric utilities, which account for about 80% of the gas used for electric generation in the eleven Western States, are estimating the increase at an average annual rate of 0.5% compounded through 1990 or about 1¢ per Mcf every five years.

Residual fuel oil prices have also stabilized in the past few years after rising in the earlier years; this is shown on Table 39. However, as conventional cracked residual oil production is phased out on the West Coast, and it becomes necessary to import fuel oil to meet requirements, the cost is expected to increase. Table 40 presents data on fuel oil prices for electric utility generation. In Southern California, which accounts for more than 70% of all the oil requirements for electric generation in the eleven Western States, it is expected that oil consumed after 1980 will be largely low sulfur, low ash fuel. Because low sulfur oil is currently priced about 20% higher than conventional fuel oil and is in short supply, average fuel oil costs for electric generation in Southern California will increase substantially in the next few years and are expected to average about $2.40 per barrel in California by 1970. Thereafter, it is expected that increases will be more moderate and generally follow the trend of gas price increases. It has been reported by a utility participating in this survey that the price formula for a substantial quantity of low sulfur fuel oil under contract provides for escalation related to the posted price of 27.0–27.9 API gravity crude oil in California and to the well-head price of California gas. It is expected that low sulfur oil will increase from about $2.40 per barrel in 1970 to $2.70 per barrel in 1990. Other oil costs such as distillate and diesel fuel are expected to increase at about double the rate of low sulfur oil or approximately 1% per year.

Table 41 compares post-war coal prices in the Western States with coal prices for the United States as a whole. The relatively constant price for coal in the United States over the past 20 years, in the face of generally rising costs, reflects the effects of the increase in coal production per man-day made possible by increased mechanization and automation. In the past, coal prices in the West have generally been higher than the national average because of smaller scale production and, in some cases, lower coal quality and the inaccessibility of the deposits.

Table 42 presents a similar comparison for prices paid for coal by electric generating utilities. The use of coal for electric generation in the West has increased substantially over the past five years. However, past trends of prices paid for coal are not necessarily indicative of the prices which can be expected in the future when an even greater use of coal for electric generation in the West is anticipated. Improvement in productivity for both surface and underground mines should provide significant stability to coal prices.

Direct mining costs at predicted production rates (See Section J) are expected to be reduced to about 8 cents per million Btu's for good quality bituminous coal or 10 cents per million Btu's if the average energy conversion equivalent of 20,000,000 Btu/ton is used.

Average price of coal in the West Region for electrical power production is expected to remain relatively stable, climbing gradually during the latter part of the forecast period. The labor component is estimated to escalate at about 4.8% per year, the materials and supplies component at about 1–2% compared with general inflation at 1.7% per year. Offsetting these factors will be improving productivity. Although coal prices for any given mine will escalate in response to the above factors, modernization at about 10-year intervals (approximate pay-out time for heavy duty equipment) to take advantage of equipment improvements is expected to keep coal competitively priced.

In summarizing price of coal to electric power plants in the West Region, the Nathan Report [14] indicates costs ranging from 9.8 cents per million Btu's to 20.1 cents per million Btu's for various coal fields. The lower figures represent areas in the Powder River Basin of Montana and Wyoming.

The weighted average mine price for coal in the Rocky Mountain area, the area of principal growth in coal-fired generating stations for the next several years is estimated at $2.85 per ton in 1970 and is expected to increase to $3.60 per ton by 1990.

Table 43 permits comparison of the costs of various fuels used for electric generation in the Western States.

P. Cost of Transporting Energy

The relative costs of transporting the various forms of energy are in many ways the key to the fuels and energy problem, particularly in the West, where the distances involved average greater than in the East. Table 44 lists various forms of energy in order of increasing cost of transportation and is graphically illustrated on Chart 7. In terms of cost per Btu or per kwh, nuclear fuel transportation is so cheap that nuclear generation should find no geographical obstacles from a transportation standpoint. The low transportation cost for nuclear fuel makes it economically feasible to import supplies from any part of the world.

When moved by tanker, transportation rates for oil are very low—second only to nuclear fuel. Oil has a high heat content in proportion to volume, and its liquid state facilitates loading, unloading, compact storage, etc. So, to a somewhat lesser extent than for nuclear fuel, oil can be brought in from any part of the world. Transportation overland, however, is not as low cost as by tanker; hence, oil should continue to be used for a long period of time in coastal areas and along navigable waterways for electric power generation. In the large load centers where air pollution is a factor, fuel oil having a very low sulfur content will gradually displace fuel oil containing high percentages of sulfur. Pipeline movement of oil costs a little more than tanker movement, and still more expensive is rail or tank truck transportation. (See Table 44 and Chart 8)

Gas costs more to move by pipeline than does oil, because gas, even under compression, contains less energy per unit volume than does oil. Thus it requires a larger capital investment per Btu moved in the case of gas. While some gas pipelines cross bodies of water, gas in the gaseous state generally cannot be moved freely except overland. However, advances in the technology of transporting natural gas in the liquid state (LNG) indicate movements over water are becoming competitive, particularly to markets where scarcity results in a higher price or additional gas supplies are required to displace fuel oil at coastal load centers to alleviate air pollution. (See Table 44 and Chart 9)

Because the West already has a network of major gas transmission pipelines, as shown on Map 2, Major Natural Gas Fields and Pipelines in Western United States, the problems of transporting future gas supplies in the gaseous state to a considerable extent already have been solved. These pipelines and others to be built or increased in capacity, together with existing commitments or plans for gas purchase assure increasing gas supplies for much of the forecast period if deliverability from natural gas fields can keep pace with demand. Future transmission of gas by pipeline may be in the liquid state in order to take advantage of volume reduction. One of the attractive features of LNG is the great volume reduction, permitting storage in manufactured containers of very large reserves of gas. A great deal of technological progress must be made, however, before the first LNG pipeline is built.

Coal transportation costs heretofore have been more than for gas, but some estimates for coal slurry pipelines—pumping powdered coal mixes with water or oil—and for integral train movement appear competitive with gas pipelines. Actual movements utilizing an integral train in the West Region are not yet firm, but a recent proposal by a midwest railroad involves renting an entire special train to the shipper; these rent-a-train rates would be in the mid-range of the estimates shown. (See Table 44 and Chart 11) Integral trains would haul coal between the two fixed points, the mine and the unloading point, using new and larger cars built especially for semi-permanent hookup in a train with locomotives at each end and perhaps in the middle. Such train need not turn around, but could simply reverse its direction at the end of each trip. Unit, or shuttle, train coal movement—

[14] Robert R. Nathan Associates, Inc.—The Potential Market for Far Western Coal and Lignite, 1965. Prepared for the Office of Coal Research, Dept. of Interior, Washington, D.C.

using present types of equipment between two fixed points—appears to cost more than gas pipeline transportation. Evidence that unit train rates are being attained is seen in the fact that the 1964 average coal hauling rates in the Western States coincides with the upper limit suggested for unit car rates; rates for some hauls in the 800-mile plus category are in the mid-range of the estimates shown. (See Chart 11)

Coal transported by slurry pipeline will be initiated in the West when a 275-mile x 18″ pipeline is completed in 1970 to transport coal from Black Mesa, Arizona to Mohave, a 1500 megawatt generating station on the Colorado River in Nevada. This will be the only coal slurry pipeline in the United States although a shorter one was previously operated in Ohio for several years. Transportation costs of coal transported by slurry pipeline vary depending upon volume, with lower rates being achieved for large volumes, i.e., over 5 million tons. Expected consumption at Mohave will be about 5 million tons a year of which about 4 million tons will produce electric power for use in California. In addition, about 6,000,000 tons of coal will be consumed at the two new Four Corners generating units near Farmington, New Mexico. About 3,000,000 tons will be used at this plant to provide power for California. Approval to build a coal-fired plant in California has received much opposition even though its location would be remote from major load centers so it seems probable there will be no consumption of coal as such within California.

Of the forms of energy listed in Table 44, electricity generally is the form most expensive to transport. (See Table 44 and Chart 12) Because of line loss and the increased transmission costs, it has usually been less costly, per kwh delivered to point of use, to build the generating plant close to the load center rather than at the mouth of the coal mine. However, advances in extra high voltage (EHV) transmission, such as 500 kvac, indicate favorable economics for use of coal to generate electricity in New Mexico and Utah for high voltage transmission to California. Because of the growing number of interconnections between the transmission systems in the West Region, such as interties between the Pacific Northwest systems and the Southwest systems, the reliability factor becomes very important. In effect, the interties replace thermal generation at the load center. The increase in reliability for EHV transmission systems adversely affects the economics, i.e., dual circuits cost more than a single circuit.

It should be noted that proposed high voltage interties [15] designed to provide a strong connection between the Northwest Subregion and the central United States will pass over some of the lowest cost coal in the West Region. Large coal-fired plants may be built in this area to take advantage of the economics of mine-mouth location. Should this occur, the projected fuel mix for the West Region will involve a substantial modification.

Generally, in the West Region the various primary energy sources are, except for environmental regulations, competitive, since in many cases low production cost can offset high transportation cost, and vice versa.

Q. Cooling Water Supply Influence Upon Fuel Mix

Advisory Committee Report No. 18 [16] on Fuel for Electric Generation in Western United States prepared for the Federal Power Commission National Power Survey 1964 report was criticized [17] for understating the potential thermal electric generation that would be coal fired, particularly for use in California. The 1963 conclusion was based upon the then existing economics of alternatives, which was well before development of joint participation projects permitted applying the economies of scale to mine-mouth coal plants remote from Pacific Coast load centers. Furthermore, it was concluded that water rights in the coal bearing states within feasible transmission distance would be so jealously guarded that only limited amounts would be available for electric generation for transmissions to California, which amounts to exporting water to California. Accordingly, the estimate excluded coal then considered uneconomic in comparison with alternatives and coal not then associated with firm water supplies needed for power plant operation. This review continues that basis of appraisal. As shown in the foregoing Section F (Energy Resources Mix for Electric Utility Generation) this 1968 appraisal by the West Region utilities indicates a re-

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[15] Transmission Study 190, Office of the Chief Engineer, Bureau of Reclamation, Denver, Colorado 80225—Att. D–209, February 1968

[16] Ibid., p. III–3–47.

[17] The Potential Market for Far Western Coal and Lignite dated December 27, 1965 by Robert R. Nathan Associates, Page X–19.

duced potential for coal as compared with the assessment five years ago. This is primarily due to a change in the coal-nuclear ratio in the Pacific Northwest (explained in more detail in Section J—Coal) and which more than offsets an increase in the consumption of coal for California's electric energy.

The change in the California component is directly related to and limited by water supplies as well as the inter-relationship between nuclear generation cost, coal mining costs, and nuclear generating plant siting.

The recent experience of four Southwest area utilities in attempting to secure cooling water supplies, is the basis for their continuing to limit the use of coal for California electric energy to water supplies known to be available for that purpose.

Construction now in progress of a 1500 MW plant at Four Corners, New Mexico will require production of 5½ million tons of coal per year of which about 48% will be for energy for California. Additional water for about 1500 MW is believed to be available and New Mexico coal producers are attempting to secure necessary additional water rights.

Construction now in progress on the 1500 MW plant at Mohave in Southern Nevada will be fueled with 5 million tons a year of Arizona coal delivered through a 275-mile x 18″ diameter slurry pipeline. About 4 million tons a year will be for California electric energy. This project is to be jointly owned by Southern California Edison Company, Los Angeles Department of Water and Power, Salt River Agricultural Improvement and Power District, and Nevada Power Company. Southern California Edison Company initiated the project and attempted to secure cooling water for a 3000 MW installation, but was able to get only half that amount.

Arizona Public Service Company, San Diego Gas and Electric Company and Southern California Edison Company have through their subsidiary companies acquired coal leases on the Kaiparowits Plateau in Southern Utah about 12 miles north of Lake Powell. The three utilities contemplated developing as much as 5000 MW of electrical generation capacity. The State of Utah approved their application for 102,000 acre feet per year of water conditioned upon a showing of intent to make beneficial use by November 30, 1970, and starting actual use by 1975 with such water rights to expire in 2010. These utilities report that after more than two years of continuous negotiation with the Bureau of Reclamation, a satisfactory water service contract is expected, making the Utah water allotment available.

While the Kaiparowits coal field involves relatively higher cost underground mining and the project might not develop in any case because of economics, as of the present time the lack of assured water caused the utilities to leave it out of their estimates of coal production used to generate electrical power for California.

In 1967 and 1968, the Los Angeles Department of Water and Power attempted to buy water from the Mohave Water Agency for 1500 MW of coal-fired generation to be located someplace between Victorville and Dagget, California. The coal probably would have been supplied from New Mexico, Arizona or Utah. On February 20, 1968, directors of the Water Agency voted not to sell water to the City of Los Angeles for that purpose. Consequently Los Angeles is attempting to build another oil and gas-fired generating unit at its Scattergood station in Los Angeles on the Pacific seacoast.

These experiences have persuaded the California utilities that their assessment of the coal potential should include only the amount that is economic in comparison with alternatives and associated with a firm water supply.

Perhaps the best evidence of their judgment may be found in the recent selections of new thermal generating capacity as follows:

Company	Plant	Capacity MW	Fuel	Date announced	Operating date
S.C.E.	Ormond Beach #1	790	Oil & Gas		1971
P.G. & E.	Diablo Canyon #1 and #2	2130	Nuclear		1972 & 1974
P.G. & E.	Pittsburg #7	735	Oil & Gas		1972
L.A.D.W.P.	Scattergood #3	450	Oil & Gas		1972
S.C.E.	Ormond Beach #2	790	Oil & Gas		1972
SMUD	Rancho Seco	800	Nuclear		1973

While it is well known that the potential western area coal resources are vastly greater than the water supplies needed for development, the seriousness of the water limitation is less well known and continues to be misunderstood. (Amazingly so in some cases, for example, the recurrence of a persistent fallacy [18] in the Nathan Report that once-through cooling is not a consumptive use of water).

R. Public Policy Influence Upon Fuels Mix

Public policy at the federal, state and local levels—in relation to air pollution control, water utilization, natural gas regulation, control of oil imports, nuclear plant siting, electric system reliability and energy policy coordination—has a vast influence upon the mixture of fuels that may be used in the future for electric generation in the Western Regions.

A change in practices and procedures in any given area inevitably has an impact upon the utilities' fuel utilization practices and will force a change in the fuel mix. It is of interest to know how far into the future projections of the type undertaken in this report are reasonably valid. Therefore, it is necessary to consider recent actions in such areas of public policy.

Air Pollution Control. Two Southern California utilities, in order to comply with local air pollution control requirements, have changed to the use of a low sulfur fuel oil (.5% sulfur or less) to supplant the use of cracked residual oil of about 1.75 to 2.0% sulfur content at a severe cost increase (about 30%). This is reportedly due to the utilities' inability to secure Federal Power Commission authorization for sufficient supplies of natural gas.[19] The principal source of low sulfur oil supply is imported low sulfur crude oil which is processed by distillation to remove light products and to yield a low sulfur residual oil. Domestic supplies of low sulfur crude may become available in Alaska or offshore California.

Other potential solutions to air pollution from combustion of fuel oil may include refinery processing to extract sulfur products from high sulfur crude and residual oils and treatment of combustion gases to extract undesirable substances. The method selected may depend upon the availability of raw materials which in the long run will probably be determined by national policy relating to the importation of foreign source oil which costs on the average $1.00 or more a barrel less than domestic oil. The differential could be used to offset cost of sulfur removal to prevent air pollution.

This illustrates the interrelationship of several areas of public policy. The ever-tightening air pollution control regulations enacted by local government (state and federal air pollution control laws also apply [20] [21]) have involved Federal Power Commission gas regulation and the Oil Import Control Administration of the Department of the Interior, which resulted in a relaxation of regulations, permitting the importation of low sulfur oil.

State and Federal Control of Water Utilization and Thermal Pollution. Some of the dense load centers, particularly in the Southwest, but increasingly so in the Northwest, plagued with gasoline air pollution and under public criticism for industrial fuel burning may be supplied by remotely located electric generation. There is a definite limit on the amount of water that may be counted upon for such remote generation in the Southwest as is explained in more detail in the previous section. It is within the authority of some states having water rights that could be allocated for electric power production and within the authority of the U.S. Department of the Interior, Bureau of Reclamation, to expedite or impede use of water for such purposes in several situations. Accordingly, this is another area in which state and federal government agencies influence the future fuel mix as the availability of water at inland sites directly limits the amount of thermal generation that is potentially available from coal.

Legislation is under discussion in Congress to enact controls on the thermal pollution of bodies of water. Potential impact upon water temperature has already become a factor affecting design of some power plants located on rivers. This is another area of public policy that will influence the fuel mixture.

Federal Power Commission Gas Regulation and Gas Competition. Oil and gas-fired thermal generating stations located in the coastal load centers of California use interruptible gas as the preference

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[18] The Potential Market for Far Western Coal and Lignite dated December 27, 1965 by Robert R. Nathan Associates, Page IX–13.

[19] Federal Power Commission Opinion No. 500.

[20] State of California Health and Safety Code, Section 24260 et seq. Rules and Regulations, Air Pollution Control Districts.

[21] Air Quality Act of 1967. Subject Law 90–148; 81 Stat. 485.

fuel supplemented by residual fuel oil and, as previously stated, low sulfur fuel oil which has become a compulsory requirement in some areas. Therefore, the impact of Federal Power Commission regulatory policy and each decision of the Federal Power Commission in a major gas certificate case is of importance in determining the anticipated fuel mixture. A significant example was the decision of the so-called Gulf Pacific Project (FPC Opinion No. 500) which rejected a proposed project for Los Angeles area electric utilities for an assured supply of gas for air pollution control purposes. Current proceedings before the Federal Power Commission involve recommendations of the Federal Power Commission staff as to the level of gas service that should apply to California's electric generation in the near future. The California utilities have estimated that they expect to consume, as an average over the forecast period, about 20% of their future thermal requirements in the form of gas. Whether they will or not will depend upon FPC policy, including policy on the field price of gas.

National policy with respect to competition to supply gas is in the process of being confirmed in the adjudication of the restraint of trade action of the Department of Justice against El Paso Natural Gas Company system and the contention that the merger restricted competition in the supply of gas to California. The United States Supreme Court ordered El Paso Natural Gas Company to divest the Pacific Northwest system and on June 21, 1968 the U.S. District Court found the Colorado Interstate Gas Company qualified to acquire the divested property. The significance of this case seems to be that the policy of the United States is to enhance competition in the supply of gas to California for electric generation.

Oil Import Control. In 1959 the Office of Civil Defense Mobilization (now the Office of Emergency Planning) recommended that restrictions should be imposed on the importation of oil into the U.S. Since 1959, various Presidential proclamations have set up administrative procedures for such control designed to meet the needs of Petroleum Administration District V in which is located almost 85% of the West Region thermal electric load. The utilities may not import oil directly; only established refiners are permitted to do so and until recently, there was no need to import fuel oil because domestic residual oil was adequate in quantity. When the domestic fuel oil was found inadequate in quality by local County level air pollution control authorities and the Federal Power Commission failed to authorize adequate gas supplies, it became necessary to seek a change in the Oil Import Regulations to gain access to low sulfur foreign oil. In January, 1968 by Presidential Proclamation No. 3823 specific recognition was given to this need and Secretary Udall promulgated working regulations to implement this important policy change. Certain segments of the oil producing industry are opposing the change and have initiated legislation to take administration of oil imports away from the Department of the Interior by substitution of rigid quota laws which would require congressional action for further change. Because this program is subject to further change by Presidential Proclamation administrative procedure or congressional action, the national policy with respect to oil import control will continue to have an important bearing upon the fuel oil mixture.

Nuclear Generating Plant Siting. Perhaps two of the most dramatic examples of how nuclear plant siting policy may influence choice of alternatives have occurred in the West Region, both in California. Pacific Gas and Electric Company decided to abandon its proposed Bodega Bay nuclear unit because of delays relating to site approval after considerable expenditure and investigative work on the site. Fortunately, P.G. & E. was able to act in time and substitute alternative oil and gas-fired generation for this block of capacity.

The City of Los Angeles Department of Water & Power first applied for permits to build its Corral Canyon (Malibu) nuclear plant in 1963 and still has not received AEC site approval, owing to an issue on the amount of differential ground displacement due to earthquake faulting which the facility must be designed to withstand. The L.A.D.W. & P. reports efforts are continuing to secure approval of a redesigned plant to meet revised standards of earthquake resistance. The delay has forced the L.A.D.-W. & P. to make earlier than anticipated commitments for coal-fired generation and to propose construction of another oil and gas-fired plant in the Los Angeles Basin (Scattergood No. 3).

Electric System Reliability. Potential requirements for reliability may influence the investment in transmission facilities which can determine the economic feasibility of mine-mouth coal-fired generation. For example, the distance from Southern California to sites where additional coal-fired generation might be located in Arizona, New Mexico and Utah averages

about 500 miles from the load center. One utility reported that the breakeven cost of coal to be competitive with nuclear energy at such sites would have to be about 10¢/M^{2}Btu's in 1990.

Energy Policy Coordination. In November of 1967 President Johnson appointed Mr. S. David Freeman, Director of the Energy Policy Staff, in the Office of Science and Technology, in recognition of the need for overall coordination of energy policy as it related to problems in finance, trade, defense, public health, utility regulation and antitrust laws.

Mr. Freeman announced on February 11, 1968 his office will have direct access to the President on energy problems through the OST and that he will oversee a broad energy study to be made over the next two years if Congress appropriates needed funds of $500,000. The study will include: (1) substitutability among oil, gas, coal and nuclear energy sources; (2) energy and air pollution control, including impact on fuel industries of drastic controls on fuels particularly sulfur content; (3) potentialities involved in new energy sources, including the impact of potential new energy sources on current regulatory practices, e.g. coal gasification on natural gas regulatory procedures; (4) security of supply, including a review of import controls; (5) evolutionary developments, such as impact of an electric car on the oil industry. This tends to indicate that more than ever before public policy affecting the fuel mix will be made and changed from time to time by the Office of the President.

It is clear that because the future fuels mix for electric generation in the western area is so heavily dependent upon public policy in six areas, some involving all levels of government and subject to change from time to time, that it is not appropriate to consider the estimates of resources mix ratios as much more than broad trends. The ratios can be reasonably well estimated for five years in the future, but not for ten years or longer.

S. Geothermal Energy

Geothermal, or earth, energy is not a fuel but it is a source for electric generation and, therefore, should be included in this report. Natural hot springs have long been used for baths or to heat homes in areas were such springs occur. Early in the 1900's, geothermal steam was first used to produce electricity at Larderello in Italy. In 1922, a project to produce electricity from steam at The Geysers in Sonoma County, California was abandoned in the face of competition from hydro generation and the rapid growth of oil production in California.

With the tremendous growth in the use of electric energy, interest in geothermal steam resources has been greatly stimulated. Steam fields at Larderello now produce over 400,000 kw's of power, and newly developed geothermal fields in New Zealand also produce about 400,000 kw's of electrical energy. In other countries around the world, especially Iceland, efforts are being made to develop geothermal heat sources.

In the United States, the West Region contains numerous potential geothermal areas. Geologically, the region is tectonically active and characterized by faulting and recent volcanic activity. The Geysers became the focal point for a resurgence of interest in the use of geothermal steam in California, and in 1960 the Pacific Gas and Electric Company became the first utility in the United States to produce electric power from geothermal energy. Steam wells drilled by the Magma Power Company and the Thermal Power Company, as joint venturers, now supply energy to four generating units having a combined capacity of about 80,000 kw's. Pacific Gas and Electric Company has scheduled an additional 110,000 kw's of generating capacity as the steam field is developed and enlarged. The units have performed very well, maintaining high capacity factors and are attended only eight hours a day, with the units being automatically tripped if there is any plant trouble.

The Imperial Valley region of Southern California is also the site of a potentially large geothermal energy source. Here, however, an extremely saline brine is produced with the steam. Just south of the border the Mexican government has blocked out a steam field about 20 miles southeast of Mexicali. Plans call for the installation of generating facilities using this energy source.

Use of low boiling point liquid, such as Freon, are being evaluated and if such methods are economically feasible, relatively low temperature hot springs could be utilized for the production of electric energy. With interest in the utilization of geothermal energy on the upswing, it seems likely that other geothermal projects, economically competitive with conventional and nuclear fuels, will be developed throughout the West Region.

T. Oil Shale

Very large resources of oil (kerogen) shale occur in the West Region. An estimate of recoverable reserves of oil from shale is given in Table 35. The bulk of the reserve is in the Piceance Basin of Colorado, northeast of Grand Junction, but substantial amounts also occur in the Unita Basin in Utah and the Green River and Washakie Basins in Wyoming.

Considerable research effort has been, and is currently being, made to find ways of obtaining shale oil at competitive costs. The various recovery concepts and associated problems are too involved to be discussed in this brief summary and the reader is referred to the extensive literature available on oil shale mining and shale oil production. It is not expected that oil from shale will have any significant impact upon the energy balance in the West Region during the forecast period.

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Subregion 1—California
Net Systems Input—1966

Company	*KWH*
Pacific Gas & Electric Co.	42, 988, 264, 000
Southern California Edison Co.	36, 739, 031, 125
Los Angeles Department of Water & Power	12, 586, 633, 342
U.S. Bureau of Reclamation, Dept. of the Interior	5, 299, 172, 000
San Diego Gas & Electric Co.	4, 416, 028, 916
Sacramento Municipal Utility District	2, 921, 310, 000
Imperial Irrigation District	774, 793, 942
Burbank Public Service Department	663, 691, 134
California-Pacific Utilities Co.	598, 532, 502
Pasadena Municipal Light & Power Department	595, 228, 925
Modesto Irrigation District	569, 257, 677
Glendale Public Service Department	462, 786, 960
Turlock Irrigation District	[1] 341, 990. 430
Metropolitan Water District of Southern California	None

[1] 1965.

Subregion 2—Northwest States
Net Systems Input—1966

Company	*KWH*
Bonneville Power Administration	43, 677, 274, 000
Pacific Power & Light Co	11, 619, 303, 000
Portland General Electric Co	6, 947, 588, 000
Idaho Power	6, 764, 373, 000
Seattle Department of Lighting	5, 946, 784, 000
Puget Sound Power & Light Co	5, 491, 719, 398
The Montana Power Co	4, 546, 929, 000
Washington Water Power Co	4, 016, 426, 000
Tacoma Public Utilities—Light Division	3, 349, 904, 597
Consumers Public Power District	1, 777, 076, 690
Eugene Water & Electric Board	1, 143, 346, 225
Montana-Dakota Utilities Co	784, 176, 771
Black Hills Power & Light Co	525, 007, 191
Public Utility District No. 2 of Grant County	506, 286, 273
Public Utility District No. 1 of Chelen County	266, 923, 986
Public Utility District No. 1 of Douglas County	None
Unieed States Dept. of the Interior Bureau of Reclamation	([1])
U.S. Army Corps of Engineers	([1])
Washington Public Power Supply System	([1])

[1] Included with Bonneville Power Administration

Subregion 3—Rocky Mountain
Net Systems Input—1966

Company	*KWH*
Public Service Company of Colorado	5, 484, 207, 861
Utah Power & Light Co	5, 089, 006, 000
Arizona Public Service Co	4, 681, 672, 050
Salt River Project	3, 174, 807, 422
Nevada Power Co	2, 329, 707, 000
El Paso Electric Co	1, 808, 489, 000
Community Public Service Co., New Mexico Division	1, 794, 798, 364
Public Service Company of New Mexico	1, 681, 629, 600
Tucson Gas & Electric Co	1, 655, 029, 163
Sierra Pacific Power Co	1, 276, 515, 000
Colorado-Ute Electric Association, Inc.	[1] 635, 504, 211
City of Colorado Springs, Department of Public Utilities	614, 293, 445
Southern Colorado Power Division, Western Power & Gas Co	491, 367, 500
Plains Electric Generation & Transmission Cooperative, Inc	[1] 317, 802, 579
Arizona Electric Power Cooperative, Inc	224, 212, 736
Western Colorado Power Co	165, 445, 000
Moon Lake Electric Association, Inc	159, 044, 294
Provo City Power Department	147, 320, 900
U.S. Bureau of Indian Affairs, Dept. of the Interior	113, 068, 089
Fort Collins Light & Power Department	54, 395, 680
Truckee-Carson Irrigation District	43, 762, 000
St. George City Utility Commission	31, 071, 738
Raton Public Service Co	25, 471, 000
Logan City Municipal Power & Light Department	10, 554, 271
Arizona Power Authority	None
Citizens Utilities Co., Kingman Division	None
Citizens Utilities Co., Nogales Division	None

[1] 1965.

National Power Survey—1990
Task Force on Fuels
West Regional Advisory Committee

Instructions for Questionnaire

Part I requests estimated data on an annual basis at five-year intervals on amount of generation and cost of fuel.

Total net generation is divided into the thermal and hydraulic categories. Thermal generation as reported should include any energy required for pump storage operations. Thermal generation is

further broken down into percentages from coal, oil, gas, nuclear and internal combustion sources. Internal combustion includes both piston and turbine units.

Fuel costs on a company average basis are requested in cents per million Btu as delivered to or alongside the stations. Where available, the coal cost should be broken down into the price at the mine and the cost of transportation.

The last item, 6e, applies to those utilities with fossil generation costs in excess of nuclear generation costs. The information requested is the price to which fossil fuel would have to drop to match nuclear fuel generation.

Data requested in Part I should be that which is available from the long-term forecasts by the appropriate planning group of the company. As such it would reflect each company's individual thinking as to future trends, based on their normal methods of computation and best estimates to 1990.

Part II calls for data that reflects each organization's thinking concerning future fuel trends. Space is also provided for comments or brief discussions in addition to the cost data and other related information. Comments should include present and future conditions and anticipated changes.

Part III is similar to Part II, but for nuclear fuel.

National Power Survey—1990
Task Force on Fuels
West Regional Advisory Committee

Company

Address

Part I—Estimate Future Generation and Cost on an annual basis showing actual figures for 1966 and projections on a five-year basis for 1970–1990.

1. Year
2. Total Net Gen.-mwhr x 1000
   a. % Thermal
   b. % Hydro
3. Thermal Net Gen.-mwhr x 1000
   a. % Coal
   b. % Oil
   c. % Gas
   d. % Nuclear
   e. % Int. Com.
4. Hydro Net Gen.-mwhr x 1000
   a. % Conventional Hydro
   b. % Pumped Storage
5. Sys. Net Heat Rate-Btu/kwhr
6. Unit Cost ¢/MBtu
   a. Coal
      (1) FOB Mine
      (2) Transportation
   b. Oil
   c. Gas
   d. Nuclear
   e. N/F breakeven

Part II—Fossil Fuel Forecast.

Coal

1. Quantity (Short tons)
2. Cost ($/ton at the mine)
3. Transportation (¢ per ton mile):
   Railroad:
      Conventional
      Unit Train
      Integral Train
   Barge
   Truck
   Slurry Pipeline
   Other
4. Contractual arrangement (% requirement in each category):
      Spot purchase
      1 Year
      Short term
      Long term
      Other
5. Source (Geographic area or district)
6. Remarks

Oil

1. Quantity (million barrels)
2. Cost $/bbl:
      Residual (Bunker & High Viscosity)
      Low Sulfur*
      Distillate
      Other

   *State specifications required to conform to air pollution regulations.
3. Method of shipment (% by category—Give cost if known):
      Pipeline
      Tanker
      Barge
      Rail
      Other

4. Contractual Arrangements (% of each category):
   - Spot purchase ________
   - 1 Year ________
   - Short term ________
   - Long term ________
   - Other ________
5. Remarks ________

____

____

____

Gas

1. Quantity (billion cu. ft.) ________
2. Source & Cost (Geographic) (¢/mcf.):

____

____

____

____

3. Transportation (% by category—Give cost if known):
   - Pipeline ________
   - LNG by tanker ________
4. Contractual Arrangement:

____

____

____

5. Remarks (Include possible use of manufactured gas):

____

____

____

____

____

Part III—Nuclear Fuel.

1. Quantity—Raw material:
   - U_3O_8 ________
   - Th O_2 ________
2. Cost $/pound:
   - U_3O_8 ________
   - Th O_2 ________
3. Contractual Arrangement (Fuel cycle—% of direct involvement in each category):
   - Raw material ________
   - Conversion ________
   - Enrichment ________
   - Fabrication ________
   - Reprocessing ________
   - Waste disposal ________
   - Other ________
   - Combination of fuel cycle now contracted out and future preference.
4. Remarks (Comment on fuel warranties):

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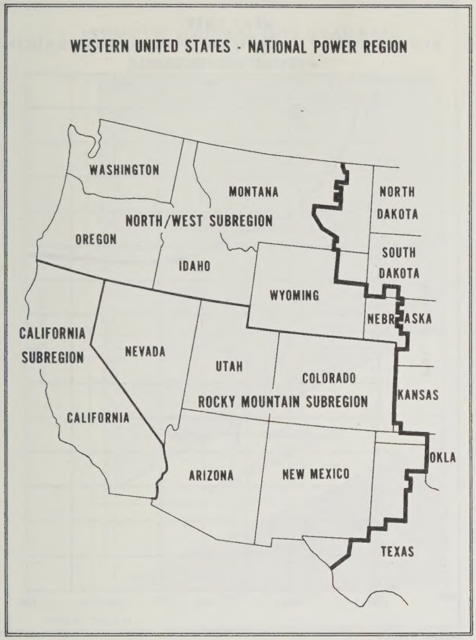
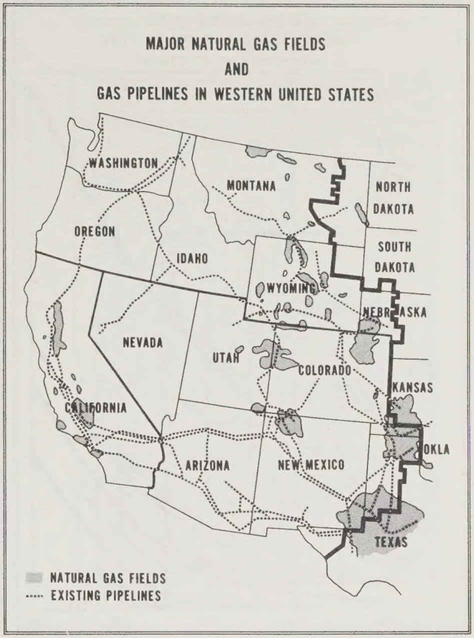
MAP 1



MAP 2



MAP 3

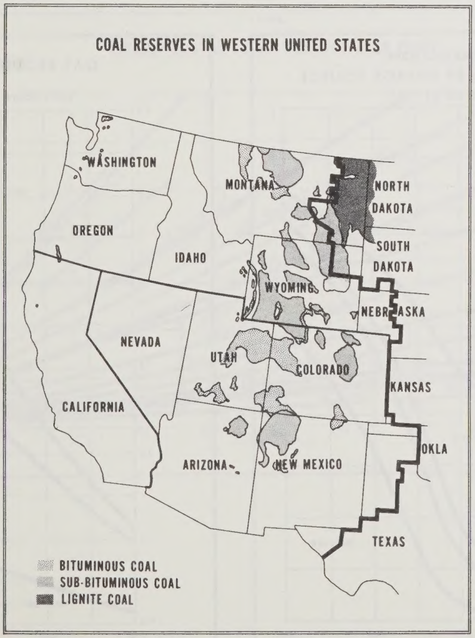
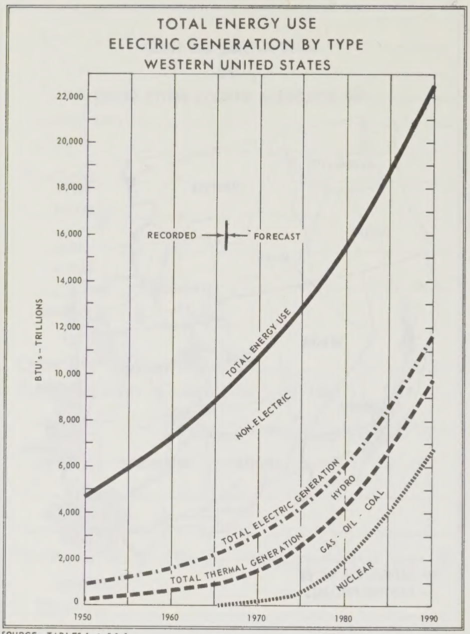
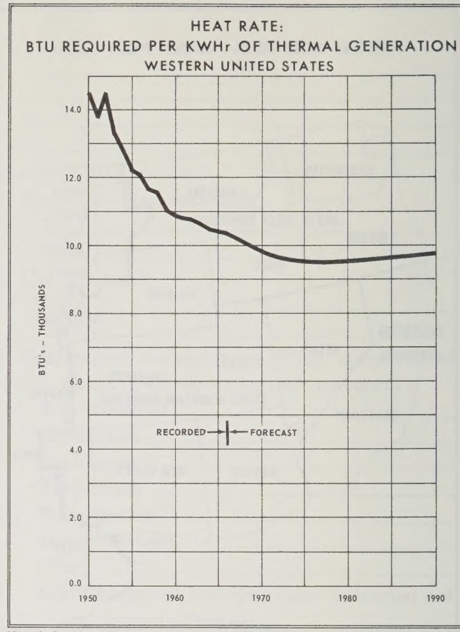


CHART 1



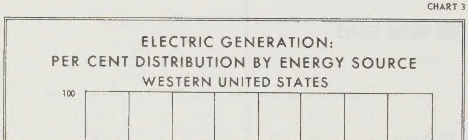
SOURCE: TABLES 1, 4, 5 & 8

CHART 2



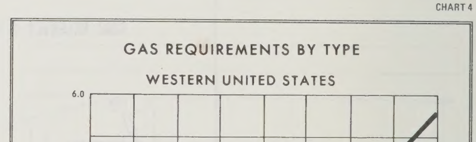
SOURCE: TABLE 6

CHART 3



SOURCE: TABLES 1 & 10

CHART 4



SOURCE: TABLE 13

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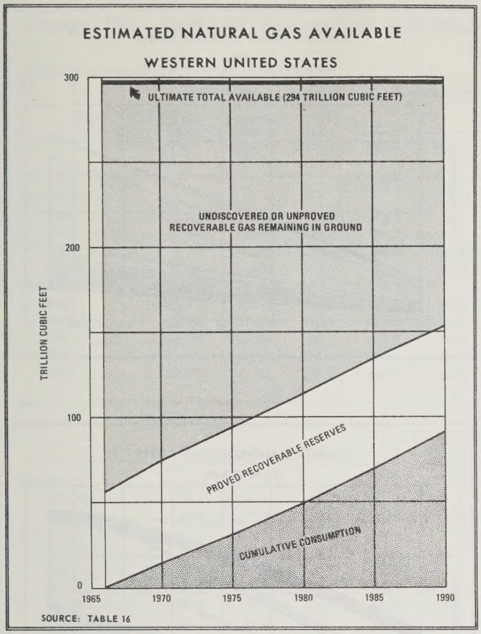

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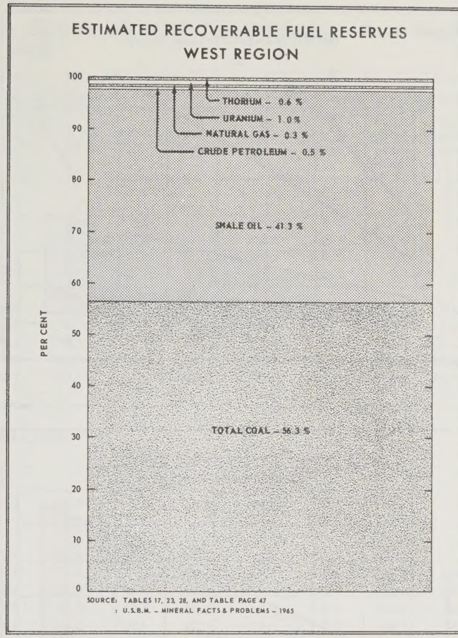

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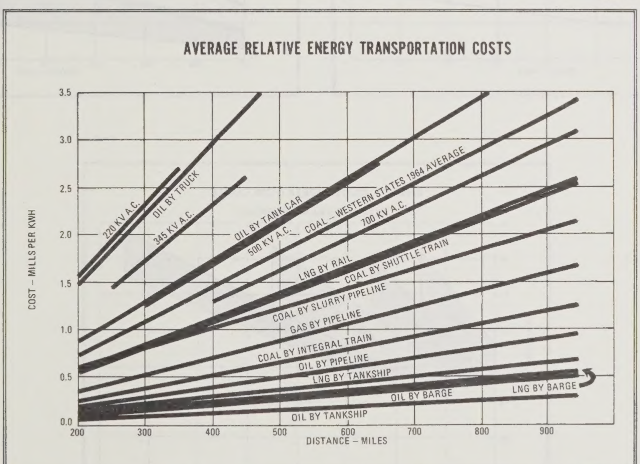

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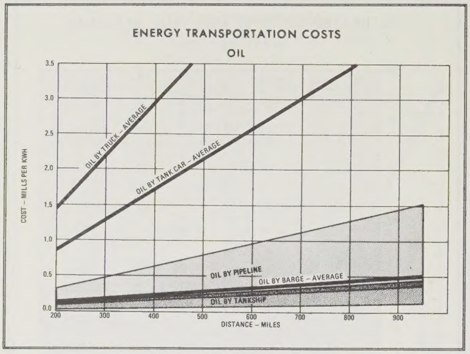

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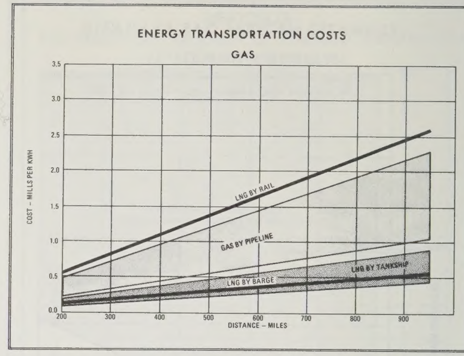

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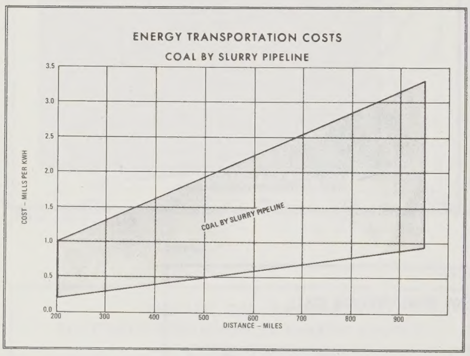

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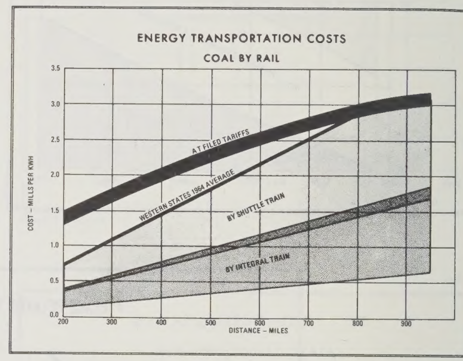

CHART 12

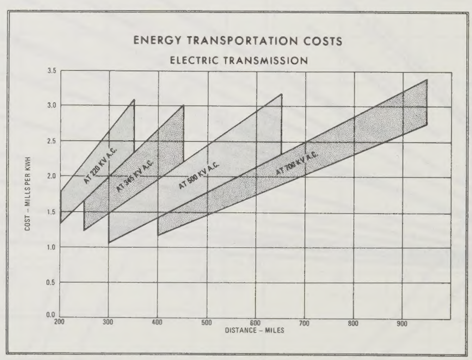

TABLE 1

Energy Use, Electrical Generation, and Electrical Generation Fuel Requirements, West Region, 1950–1990

Year	Trillion Btu		Electric utility generation, billion kwh							Electrical generation fuel requirements			
	Total energy use	Thermal elec.[1] generation	Total hydro	Thermal					Nuclear	Gas billions cu. ft.	Oil million bbls.	Coal million short tons	U_3O_8 short tons
				Total	Gas	Oil	Coal	Other [2]					
Recorded:													
1950	4,686	278	49.8	14.4	8.7	4.3	0.8	0.6	----------	127.0	10.3	0.8	0
1955	5,910	531	65.6	37.7	23.2	12.3	1.8	0.4	----------	278.9	23.4	1.2	0
1960	7,131	765	82.8	64.0	43.4	15.9	4.3	0.4	----------	458.7	26.7	2.8	----------
1965	8,904	993	119.9	88.8	63.2	11.3	13.3	0.7	0.3	628.3	18.6	7.7	14
Projected:													
1970	10,721	1,540	158.6	149.1	92.5	16.9	30.6	1.0	8.1	855.0	23.7	15.5	1,027
1975	12,905	2,655	173.3	270.2	90.1	35.0	79.8	2.6	62.7	802.0	49.7	39.7	3,590
1980	15,585	4,321	183.5	447.0	76.7	34.6	123.6	4.4	207.7	685.0	50.8	59.3	8,175
1985	18,823	6,680	194.4	690.1	68.7	31.8	168.8	6.6	414.2	641.0	50.0	79.6	11,630
1990	22,608	9,793	198.5	1,006.8	75.9	30.7	207.6	7.4	685.2	724.0	47.4	98.5	15,640
PERCENT CHANGE													
Recorded:													
1955–60	20.6	44.1	26.2	69.8	87.1	29.3	138.9	0.0	----------	64.5	14.1	121.9	----------
1960–65	24.9	29.8	44.8	38.8	45.6	−28.9	209.3	75.0	----------	36.8	−30.5	179.7	----------
Projected:													
1965–70	20.4	55.1	32.3	67.9	46.4	49.6	130.1	42.9	2,600.0	36.1	27.8	100.5	----------
1970–75	20.4	72.4	21.2	81.2	−2.6	107.1	160.8	160.0	674.1	−6.2	109.8	156.0	249.6
1975–80	20.8	62.7	9.3	65.4	−14.9	−1.1	54.9	69.2	231.1	−14.6	2.1	49.4	127.7
1980–85	20.8	54.6	5.9	54.4	−10.4	−8.1	36.6	50.0	99.4	−6.4	−1.4	34.4	42.3
1985–90	20.1	46.6	2.1	45.9	10.5	−3.5	23.0	12.1	65.4	12.9	−5.2	23.8	34.5

[1] Utility and industrial.
[2] Internal Combustion, Wood, Waste, Geothermal and Other.

TABLE 2

Energy Use Related to Economic Factors, West Region, 1950–1990

Year	(1) Civilian population July 1, thousands	(2) Personal income of civilian residents in 1965 prices, billion $	(3) Personal income per capita, in 1965 prices, $	(4) Energy use per capita, million Btu	(5) Energy Use per income dollar in 1965 prices, Btu per $	(6) Total energy use, trillion Btu
Recorded:						
1950	19, 711	44. 0	2, 232	238. 0	106. 5	4, 686
1955	23, 295	57. 8	2, 481	253. 7	102. 2	5, 910
1960	27, 403	72. 6	2, 649	260. 2	98. 2	7, 131
1965	31, 006	93. 1	3, 003	287. 2	95. 6	8, 904
Projected:						
1970	34, 650	116. 0	3, 348	309. 4	92. 4	10, 721
1975	38, 719	144. 5	3, 733	333. 3	89. 3	12, 905
1980	43, 400	180. 7	4, 163	359. 1	86. 2	15, 585
1985	48, 650	225. 8	4, 641	386. 9	83. 4	18, 823
1990	54, 241	280. 7	5, 175	416. 8	80. 5	22, 608
AVERAGE ANNUAL PERCENT CHANGE						
Recorded:						
1950–55	3. 4	5. 6	2. 1	1. 3	−0. 8	4. 8
1955–60	3. 3	4. 7	1. 3	. 5	− . 8	4. 0
1960–65	2. 5	5. 1	2. 5	2. 0	− . 5	4. 5
1950–65	3. 1	5. 1	2. 0	1. 2	− . 7	4. 4
Projected:						
1965–70	2. 2	4. 5	2. 2	1. 5	− . 7	3. 8
1970–75	2. 2	4. 5	2. 2	1. 5	− . 7	3. 8
1975–80	2. 3	4. 6	2. 2	1. 5	− . 7	3. 9
1980–85	2. 3	4. 6	2. 2	1. 5	− . 7	3. 9
1985–90	2. 2	4. 4	2. 2	1. 5	− . 7	3. 7
1965–90	2. 3	4. 5	2. 2	1. 5	− . 7	3. 8

Sources of recorded data: Col. (1), *Statistical Abstract of the United States*, 1961, page 10; 1964, page 11; 1967, page 12. Col. (2), *Statistical Abstract*, 1967, page 327; adjusted to 1965 prices by means of U.S. Consumer Price Index in *Economic Indicators*. 1967 Historical Supplement, page 95. Col. (3) = Col. (2)/Col. (1). Col. (4) = Col. (6)/Col. (1). Col. (5) = Col. (6)/Col. (2). Col. (6), from Table 4.

Sources of projections: Col. (1), 1975 and 1985, U.S. Bureau of the Census, cur. pop. reports, p–25, No. 362, in *Statistical Abstract*, 1967 page 13, Series 11–B, with declining migration rates 1970 and 1980 by interpolation; 1990 projected on the basis of a slower percentage growth rate. Col. (2) = Col. (1) × Col. (3). Cols. (3) (4) & (5) based on continuation of 1950–65 average percentage rates of change adjusted in direction of rising trend. Col. (6) from table 4.

TABLE 3

Energy Use, by Type of Energy, West Region, 1950–1990

Year	Natural gas, billion cubic feet	Petroleum products, million barrels	Liquified petroleum gases, million barrels	Coal, million short tons	Fuel wood, million cords	Electrical generation, nonfossil fuel, billion Kwh		
						Hydro	Geo-thermal	Nuclear
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Recorded:								
1950	1, 115	390	10	19. 1	4. 0	50. 1	0	0
1955	1, 631	501	17	13. 2	5. 8	65. 8	0	0
1960	2, 302	570	23	10. 8	6. 9	83. 1	(1)	(1)
1965	3, 020	657	27	17. 0	7. 2	120. 2	. 2	. 3
Projected:								
1970	3, 749	742	31	23. 6	7. 0	158. 9	. 6	8. 1
1975	4, 313	827	34	27. 1	6. 5	173. 6	2. 0	62. 7
1980	4, 701	898	37	65. 9	6. 0	183. 8	3. 8	207. 7
1985	5, 094	943	39	85. 4	5. 5	194. 7	5. 6	414. 2
1990	5, 476	985	41	103. 5	5. 0	198. 8	5. 6	685. 2
PERCENT CHANGE								
Recorded:								
1950–55	46. 4	28. 5	70. 6	−30. 9	44. 4	31. 3	...	...
1955–60	41. 1	13. 8	30. 8	−18. 1	19. 1	26. 3	...	...
1960–65	31. 2	15. 3	18. 9	57. 7	4. 7	44. 5	456	...
1950–65	170. 9	68. 5	165. 5	−10. 8	80. 2	140. 0	...	...
Projected:								
1965–70	24. 1	13. 1	13. 1	38. 8	−2. 8	32. 2	218	2, 600. 0
1970–75	15. 0	11. 3	11. 4	14. 8	−7. 1	9. 3	235	674. 0
1975–80	9. 0	8. 6	8. 0	143. 2	−7. 7	5. 9	89	231. 0
1980–85	8. 4	5. 0	5. 5	29. 6	−8. 3	5. 9	48	99. 0
1985–90	7. 5	4. 5	4. 4	21. 2	−9. 1	2. 1	...	65. 0
1965–90	81. 3	50. 0	49. 7	508. 8	−30. 6	65. 1	2, 884	...

[1] Less than .05 unit.

NOTE.—Electrical Generation Includes Industrial as well as Utility Generation.

Sources of actual data: Cols. (1) and (4): U.S. Bureau of Mines, *Minerals Yearbook*, annual. Col. (2): U.S. Bureau of Mines, *District V Petroleum Statement*, annual; *District V Petroleum Demand Report*, annual; New Mexico and District IV based on estimated disappearance, that is, refinery output, net shipped in (or out), less stock change, using Bureau of Mines data in *Minerals Yearbook* and *Petroleum Statement*, annual. Col. (3): Bureau of Mines, *Shipments of Liquified Petroleum Gases*, annual. Col. (5): 1952 and 1962 data from U.S. Forest Service, *Forest Statistics for California*, 1954, p. 21, including footnote 4; *Timber Harvest in California*, 1962, p. 10; *Timber Trends in the United States*, 1965, pp. 191–192; interpolated and extrapolated on basis of lumber production in U.S. Bureau of the Census, *Lumber Production*, annual: salvage wood fuel estimated at 20% of firewood in the round; reflects up-trends in barbecues and vacation homes, and in use of presto logs and charcoal. Cols. (6), (7), and (8) Table 7.

SOURCES OF PROJECTIONS: Col. (1); Table 13. Cols. (2) and (3); Table 4 and 31. Col. (4); Table 9 plus declining non-utility use Cols. (6), (7), and (8); Table 7.

TABLE 4

Energy Use in Trillions of Btu by Type of Energy, West Region, 1950–1990

Year	Natural gas	Petroleum products	Liquefied petroleum gases	Coal	Fuel wood	Electrical generation nonfossil fuel: Hydro electric	Electrical generation nonfossil fuel: Geo-thermal	Electrical generation nonfossil fuel: Nuclear	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Recorded:									
1950.........	1, 199	2, 262	41	382	77	725	0	0	4, 686
1955.........	1, 754	2, 906	70	264	113	803	0	0	5, 910
1960.........	2, 475	3, 306	91	216	135	908	(1)	(1)	7, 131
1965.........	3, 246	3, 811	109	341	141	1, 251	2	3	8, 904
Projected:									
1970.........	4, 030	4, 304	123	472	136	1, 568	6	82	10, 721
1975.........	4, 636	4, 799	137	942	126	1, 655	19	591	12, 905
1980.........	5, 053	5, 206	149	1, 318	116	1, 741	37	1, 966	15, 585
1985.........	5, 476	5, 467	156	1, 708	107	1, 868	54	3, 987	18, 823
1990.........	5, 887	5, 714	163	2, 070	97	1, 932	55	6, 690	22, 608
PERCENT OF TOTAL ENERGY									
Recorded:									
1950.........	25. 6	48. 3	0. 9	8. 1	1. 6	15. 4	0. 0	0. 0	100. 0
1955.........	29. 7	49. 2	1. 2	4. 4	1. 9	13. 5	. 0	. 0	100. 0
1960.........	34. 7	46. 4	1. 3	3. 0	1. 9	12. 7	(1)	(1)	100. 0
1965.........	36. 5	42. 8	1. 2	3. 8	1. 6	14. 0	(1)	(1)	100. 0
Projected:									
1970.........	37. 6	40. 2	1. 1	4. 4	1. 2	14. 6	. 1	. 8	100. 0
1975.........	35. 9	37. 2	1. 1	7. 3	1. 0	12. 8	. 1	4. 6	100. 0
1980.........	32. 4	33. 4	. 9	8. 5	. 8	11. 2	. 2	12. 6	100. 0
1985.........	29. 1	29. 0	. 8	9. 1	. 6	9. 9	. 3	21. 2	100. 0
1990.........	26. 1	25. 3	. 7	9. 2	. 4	8. 5	. 2	29. 6	100. 0

[1] Less than 0.5 trillion Btu, or less than 0.05%.

Source af Recorded Data: Tables 3, 7 and 46. Electric generation at regional fossil fuel heat rates in Table 6.

Source Projections: Cols. 1, 4, and 5: Tables 3 and 45. Col. 2 and 3 together: Col. 9 less other columns with the declining rate of increase serving as a check. Col. 6: Tables 3 and 6. Cols. 7, and 8: Table 8. Col. 9: Table 2.

NOTE.—Electrical generation includes industrial as well as utility generation.

TABLE 5

Relation of Utility Generation to Total Energy Use, West Region, 1950–1990

Year	Total energy use	Electric generation at then-current fossil fuel heat rates trillion of Btu: Thermal: Nuclear	Thermal: Other	Thermal: Total	Internal combustion	Hydro generation	Total	Percent of total energy accounted for by—: Thermal: Nuclear	Thermal: Other	Thermal: Total	Internal combustion	Hydro generation	Total
Recorded:													
1950	4,686	0	207	207	4	722	933	0	4.4	4.4	0.1	15.4	19.9
1955	5,910	0	454	454	4	801	1,259	0	7.6	7.6	.1	13.6	21.3
1960	7,131	(1)	695	695	4	904	1,603	(1)	9.7	9.7	.1	12.7	22.5
1965	8,904	3	921	924	4	1,248	2,176	(1)	10.4	10.4	(1)	14.0	24.4
Projected:													
1970	10,721	82	1,387	1,469	4	1,565	3,038	.8	12.9	13.7	(1)	14.6	28.3
1975	12,905	591	1,978	2,560	6	1,653	4,228	4.6	15.3	19.9	(1)	12.9	32.8
1980	15,585	1,966	2,262	4,228	6	1,738	5,972	12.6	14.5	27.1	(1)	11.2	38.3
1985	18,823	3,987	2,675	6,612	10	1,865	8,487	21.2	14.0	35.2	.1	9.8	45.1
1990	22,608	6,690	3,077	9,767	17	1,929	11,713	29.6	13.6	43.2	.1	8.5	51.8
PERCENT CHANGE													
Recorded:													
1950–55	26.2		119.3	119.3		10.9	35.0						
1955–60	20.6		53.1	53.1		12.9	27.4						
1960–65	24.9		32.5	33.0		38.0	35.7						
Projected:													
1965–70	20.4	2,900	50.6	59.0		25.5	39.6						
1970–75	20.4	674	42.6	74.3	50	5.6	39.2						
1975–80	20.8	231	14.4	65.2		5.1	42.2						
1980–85	20.8	99	16.0	56.4	67	7.3	42.1						
1985–90	20.1	65	17.2	47.7	70	3.4	38.0						

1 Less than 0.5 trillion Btu or less than 0.05%.

Sources: Tables 2, 6, 7, and 8 Btu's for hydrogeneration obtained by use of Western Region heat rate; for other generation, by use of sub-region heat rates.

TABLE 6

Heat Rate: Average Btu Used Per Kwh of Fossil Fueled Thermal Generation, Total Electric Utility Industry, 1950–1990

Year	California	Northwest subregion [3]	Rocky Mountain subregion [3]	West region	United States	United States, percent change from 5 years earlier
Recorded:						
1950	[1] 13, 350	[1 2] 26, 836	[2] 15, 764	14, 494	14, 033	−11. 2
1951	13, 010	25, 386	14, 829	13, 810	13, 644	−14. 8
1952	13, 465	20, 070	14, 753	14, 467	13, 366	−14. 3
1953	12, 702	20, 977	13, 907	13, 281	12, 889	−18. 1
1954	12, 442	18, 467	13, 533	12, 782	12, 180	−19. 0
1955	11, 697	21, 492	12, 992	12, 207	11, 699	−16. 6
1956	11, 606	21, 820	12, 631	12, 079	11, 456	−16. 1
1957	11, 198	18, 269	12, 327	11, 648	11, 365	−15. 0
1958	[1] 11, 265	[1 2] 16, 497	[2] 11, 796	11, 533	11, 090	−14. 0
1959	10, 838	14, 906	11, 393	11, 057	10, 879	−10. 7
1960	10, 663	13, 702	11, 359	10, 918	10, 701	−8. 6
1961	10, 524	13, 245	11, 366	10, 801	10, 552	−7. 9
1962	10, 522	13, 441	11, 141	10, 770	10, 497	−7. 6
1963	10, 413	12, 047	11, 068	10, 655	10, 438	−5. 9
1964	10, 182	12, 011	11, 123	10, 474	10, 407	−4. 3
1965	10, 114	11, 900	11, 187	10, 412	10, 384	−3. 0
Projected:						
1970	9, 604	10, 500	10, 501	9, 865	9, 770	−5. 9
1975	9, 314	9, 700	10, 105	9, 536	9, 440	−3. 4
1980	9, 377	9, 700	9, 535	9, 471	9, 390	−0. 7
1985	9, 615	9, 700	9, 377	9, 597	9, 550	0. 9
1990	9, 828	9, 700	9, 356	9, 718	9, 590	1. 0

[1] Estimated by extrapolation for 1950 and by interpolation for 1958 based on trend for Pacific States.

[2] Estimated by extrapolation for 1950 and by interpolation for 1958 based on trend for Mountain States.

[3] Average of rates for individual states weighted in proportion to conventional thermal generation.

Sources of recorded data: Federal Power Commission data in Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry*, annually. Based on use of gas, oil and coal, but not nuclear or other heat sources.

Source of projections: Average of rates reported for individual utilities or subregions, weighted in proportion to projected fossil-fuel generation.

TABLE 7

Electric Generation by Energy Sources Electric Utility Industry—West Region by Subregion 1950–1990

[Billion kilowatt-hours]

Year Sub-region	Thermal: Natural gas	Thermal: Fuel oil	Thermal: Coal [2]	Thermal: Nuclear	Thermal: Other [1]	Thermal: Total	Internal combustion	Hydro	Total
Recorded:									
1950:									
California	5.8	4.1			(3)	9.9	(3)	14.8	24.7
Northwest	0.1	0.1	0.2		0.3	0.7	(3)	28.6	29.3
Rocky Mountain	2.8	0.1	0.6			3.5	0.3	6.4	10.2
Total	8.7	4.3	0.8		0.3	14.1	0.3	49.8	64.2
1955:									
California	16.3	11.7			(3)	28.0	(3)	14.6	42.6
Northwest	(3)	(3)	0.3		0.1	0.4	(3)	45.5	45.9
Rocky Mountain	6.9	0.6	1.5			9.0	0.3	5.5	14.8
Total	23.2	12.3	1.8		0.1	37.4	0.3	65.6	103.3
1960:									
California	31.7	14.6			(3)	46.3	(3)	17.4	63.7
Northwest	0.1	(3)	1.1		(3)	1.2	(3)	59.1	60.3
Rocky Mountain	11.6	1.3	3.2			16.1	0.4	6.3	22.8
Total	43.4	15.9	4.3		(3)	63.6	0.4	82.8	146.8
1965:									
California	51.6	10.4		0.3	0.2	62.5	(3)	30.5	93.0
Northwest	0.2	(3)	2.9		0.1	3.2	(3)	81.5	84.7
Rocky Mountain	11.4	0.9	10.4			22.7	0.4	7.9	31.0
Total	63.2	11.3	13.3	0.3	0.3	88.4	0.4	119.9	208.7
Projected:									
1970:									
California	79.5	16.1	5.7	3.5	.6	105.4	.1	31.1	136.6
Northwest	.0	(3)	2.5	4.6	.0	7.1	.0	117.0	124.1
Rocky Mountain	13.0	.8	22.4	.0	.0	36.2	.3	10.5	47.0
Total	92.5	16.9	30.6	8.1	.6	148.7	.4	158.6	307.7
1975:									
California	74.3	34.1	22.0	40.5	2.0	172.9	.2	32.0	205.1
Northwest	.0	(3)	21.1	19.5	.0	40.6	.0	129.3	169.9
Rocky Mountain	15.8	.9	36.7	2.7	.0	56.1	.4	12.0	68.5
Total	90.1	35.0	79.8	62.7	2.0	269.6	.6	173.3	443.5
1980:									
California	55.9	33.5	30.5	150.4	3.8	274.1	.2	32.3	306.6
Northwest	.0	(3)	37.9	54.6	.0	92.5	.0	138.6	231.1
Rocky Mountain	20.8	1.1	55.2	2.7	.0	79.8	.4	12.6	92.8
Total	76.7	34.6	123.6	207.7	3.8	446.4	.6	183.5	630.5
1985:									
California	50.1	31.0	43.6	279.1	5.6	409.4	.5	33.2	443.1
Northwest	.0	(3)	48.0	121.0	.0	169.0	.0	148.6	317.6
Rocky Mountain	18.6	.8	77.2	14.1	.0	110.7	.5	12.6	123.8
Total	68.7	31.8	168.8	414.2	5.6	689.1	1.0	194.4	884.5

See footnotes at end of table.

TABLE 7—Continued

Year Sub-region	Thermal						Internal combus-tion	Hydro	Total
	Natural gas	Fuel oil	Coal [2]	Nuclear	Other [1]	Total			
Projected—Continued									
1990:									
California	48. 5	29. 7	58. 2	422. 0	5. 6	564. 0	1. 3	36. 8	602. 1
Northwest	. 0	(3)	58. 3	228. 0	. 0	286. 3	. 0	149. 3	435. 6
Rocky Mountain	27. 4	1. 0	91. 1	35. 2	. 0	154. 7	. 5	12. 4	167. 6
Total	75. 9	30. 7	207. 6	685. 2	5. 6	1, 005. 0	1. 8	198. 5	1, 205. 3

[1] Wood, Waste, Geothermal and Other.

[2] Coal shown for California produced and utilized in Rocky Mountain Subregion.

[3] Less than 0.05 billion Kwh.

TABLE 7–A

Electric Generation by Industrial Establishments, West Region by Sub-region 1950–1990

[Billion kilowatt-hours]

Year Sub-region	Thermal and internal combustion	Hydro	Total
Recorded:			
1950:			
California	0. 9	(1)	0. 9
Northwest	1. 4	0. 3	1. 7
Rocky Mountain	2. 4	(1)	2. 4
Total	4. 7	0. 3	5. 0
1955:			
California	1. 0	....	0. 9
Northwest	1. 9	0. 2	2. 2
Rocky Mountain	2. 9	(1)	2. 9
Total	5. 8	0. 2	6. 0
1960:			
California	1. 1	(1)	1. 1
Northwest	2. 0	0. 3	2. 3
Rocky Mountain	2. 9	(1)	2. 8
Total	6. 0	0. 3	6. 3
1965:			
California	1. 2	(1)	1. 2
Northwest	1. 8	0. 3	2. 1
Rocky Mountain	3. 6	(1)	3. 6
Total	6. 6	0. 3	6. 9
Projected:			
1970:			
California	1. 2	(1)	1. 2
Northwest	2. 0	0. 3	2. 3
Rocky Mountain	4. 0	(1)	4. 0
Total	7. 2	0. 3	7. 5

See footnote at end of table.

TABLE 7–A—Continued

Year	Sub-region	Thermal and internal combustion	Hydro	Total
Projected—Continued				
1975:				
	California	1.4	(1)	1.3
	Northwest	2.2	0.3	2.5
	Rocky Mountain	4.4	(1)	4.4
	Total	8.0	0.3	8.2
1980:				
	California	1.5	(1)	1.5
	Northwest	2.4	0.3	2.7
	Rocky Mountain	4.9	(1)	4.9
	Total	8.8	0.3	9.1
1985:				
	California	1.7	(1)	1.7
	Northwest	2.7	0.3	3.0
	Rocky Mountain	5.3	(1)	5.3
	Total	9.7	0.3	10.0
1990:				
	California	1.8	(1)	1.8
	Northwest	2.9	0.3	3.2
	Rocky Mountain	5.9	(1)	5.9
	Total	10.6	0.3	10.9

[1] Less than 0.05 billion Kwh.

Sources of Recorded Data: Federal Power Commission, *Electric Power Statistics*, monthly; and *Production of Electric Energy Capacity of Generating Plants*, 1950, pages 31–34. Fuel generation is not available broken down by type of fuel.

TABLE 7–B

Electric Generation, by Energy Source, Total Electric Utility Industry and Industrial Establishments, West Region, by sub-region, 1950–1990

[Billion kilowatt-hours]

Year	Sub-region	Thermal and internal combustion	Hydro	Total
Recorded:				
1950:				
	California	10.9	14.8	25.7
	Northwest	2.0	28.9	30.9
	Rocky Mountain	6.2	6.4	12.6
	Total	19.1	50.1	69.2
1955:				
	California	28.9	14.5	43.4
	Northwest	2.5	45.8	48.2
	Rocky Mountain	12.1	5.5	17.7
	Total	43.5	65.8	109.3

TABLE 7–B—Continued

Year	Sub-region	Thermal and internal combustion	Hydro	Total
Recorded—Continued				
1960:				
	California	47.4	17.4	64.9
	Northwest	3.2	59.4	62.6
	Rocky Mountain	19.4	6.3	25.7
	Total	70.0	83.1	153.1
1965:				
	California	63.7	30.5	94.2
	Northwest	5.0	81.7	86.7
	Rocky Mountain	26.7	8.0	34.7
	Total	95.4	120.2	215.6
Projected:				
1970:				
	California	106.7	31.1	137.8
	Northwest	9.1	117.3	126.4
	Rocky Mountain	40.5	10.5	51.0
	Total	156.3	158.9	315.2
1975:				
	California	174.5	32.0	206.4
	Northwest	42.8	129.6	172.4
	Rocky Mountain	60.9	12.0	72.9
	Total	278.2	173.6	451.7
1980:				
	California	275.8	32.3	308.1
	Northwest	94.9	138.9	233.8
	Rocky Mountain	85.1	12.6	97.7
	Total	455.8	183.8	639.6
1985:				
	California	411.6	33.2	444.8
	Northwest	171.7	148.9	320.6
	Rocky Mountain	116.5	12.6	129.1
	Total	699.8	194.7	894.5
1990:				
	California	567.0	36.8	603.8
	Northwest	289.3	149.6	438.9
	Rocky Mountain	161.1	12.4	173.5
	Total	1,017.4	198.8	1,216.2

Sources of Recorded Data: Federal Power Commission, *Electric Power Statistics*, monthly; *Production of Electric Energy, Capacity of Generating Plants*, 1950, pages 31–34; and Federal Power Commission data in Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry*, 1951, 1956, 1961, and 1966.

TABLE 8

Fuels Used for Thermal Electric Generation, Trillion Btu by Type of Fuel, Total Electric Utility Industry, West Region, by Sub-region, 1950–1990

Year	Sub-region	Natural gas	Fuel oil	Coal	Nuclear	Other fuel and Geo-thermal	Total
Recorded:							
1950:							
	California	77	55	0	0	1	133
	Northwest	3	3	5	0	8	19
	Rocky Mountain	44	2	9	0	0	55
	Total	124	60	14	0	9	207
1955:							
	California	191	137	0	0	(1)	328
	Northwest	(1)	(1)	6	0	3	9
	Rocky Mountain	90	8	19	0	0	117
	Total	281	145	25	0	3	454
1960:							
	California	338	156	0	(1)	1	495
	Northwest	2	(1)	15	0	(1)	17
	Rocky Mountain	132	15	36	0	0	183
	Total	472	171	51	(1)	1	695
1965:							
	California	522	105	0	3	2	632
	Northwest	2	(1)	35	0	1	38
	Rocky Mountain	128	10	116	0	0	254
	Total	652	115	151	3	3	924
Projected:							
1970:							
	California	773	143	57	34	6	1,013
	Northwest	(1)	(1)	28	48	0	76
	Rocky Mountain	146	9	225	0	(1)	380
	Total	919	152	310	82	6	1,469
1975:							
	California	689	309	216	375	19	1,608
	Northwest	(1)	(1)	205	189	0	394
	Rocky Mountain	176	9	355	27	(1)	567
	Total	865	318	776	591	19	2,569
1980:							
	California	514	316	294	1,410	36	2,570
	Northwest	(1)	(1)	367	530	0	897
	Rocky Mountain	233	9	493	26	(1)	761
	Total	747	325	1,154	1,966	36	4,228
1985:							
	California	490	311	398	2,682	54	3,935
	Northwest	(1)	(1)	466	1,173	0	1,639
	Rocky Mountain	206	9	691	132	(1)	1,038
	Total	696	320	1,555	3,987	54	6,612

See footnote at end of table.

TABLE 8—Continued

Year	Sub-region	Natural gas	Fuel oil	Coal	Nuclear	Other fuel and Geo-thermal	Total
Projected—Continued							
1990:							
	California	490	295	556	4, 417	55	5, 543
	Northwest	(1)	(1)	563	2, 214	0	2, 777
	Rocky Mountain	306	9	803	329	(1)	1, 447
	Total	796	304	1, 922	6, 690	55	9, 767

[1] Less than 0.5 trillion Btu.

Source of Recorded Data: Federal Power Commission, *Consumption of Fuels for Power Generation*, 1951, Pages 10 & 14; *Electric Power Statistics*, Annual and Monthly; Federal Power Commission data in U.S. Bureau of Mines, *Minerals Yearbook*, Annual; and Federal Power Commission data in Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry*, Annual.

Source of Projections: Tables 6 and 7.

TABLE 9

Fuels Used for Electric Generation, by Type of Fuel, Total Electric Utility Industry, West Region, by Sub-region, 1950–1990

Year	Region	Natural gas, million cubic feet	Oil, thousand barrels	Coal, thousand short tons [1]	Nuclear fuel: Thousand megawatt-days thermal basis	Nuclear fuel: U_3O_8, short tons	Nuclear fuel: ThO_2, short tons
Recorded:							
1950:							
	California	78, 322	9, 373	0	0	0	0
	Northwest	2, 024	366	201	0	0	0
	Rocky Mountain	46, 674	521	561	0	0	0
	Total	127, 020	10, 260	762	0	0	0
1955:							
	California	183, 664	21, 953	0	0	0	0
	Northwest	1, 608	211	337	0	0	0
	Rocky Mountain	93, 652	1, 245	908	0	0	0
	Total	278, 924	23, 409	1, 245	0	0	0
1960:							
	California	322, 992	24, 051	0	0	(2)	0
	Northwest	1, 713	31	1, 002	0	0	0
	Rocky Mountain	133, 978	2, 623	1, 761	0	0	0
	Total	458, 683	26, 705	2, 763	0	0	0
1965:							
	California	492, 201	16, 692	0	37	14	0
	Northwest	2, 292	40	2, 237	0	0	0
	Rocky Mountain	133, 763	1, 823	5, 492	0	0	0
	Total	628, 256	18, 555	7, 729	37	14	0

See footnotes at end of table.

TABLE 9—Continued

Year	Region	Natural gas, million cubic feet	Oil thousand barrels	Coal, thousand short tons	Nuclear fuel: Thousand megawatt-days thermal basis	Nuclear fuel: U_3O_8 short tons	Nuclear fuel: ThO_2, short tons
Projected:							
1970:							
	California	719, 000	22, 270	2, 840	469	627	0
	Northwest	(2)	35	1, 400	593	400	0
	Rocky Mountain	136, 000	1, 400	11, 256			0
	Total	855, 000	23, 705	15, 496	1, 062	1, 027	0
1975:							
	California	641, 000	48, 320	10, 800	6, 314	2, 397	0
	Northwest	(2)	5	11, 100	1, 528	1, 038	0
	Rocky Mountain	161, 000	1, 400	17, 773	200	155	3
	Total	802, 000	49, 725	39, 673	8, 042	3, 590	3
1980:							
	California	478, 000	49, 370	14, 700	21, 272	5, 430	0
	Northwest	(2)	5	19, 900	5, 274	2, 705	0
	Rocky Mountain	207, 000	1, 400	24, 664	224	40	3
	Total	685, 000	50, 775	59, 264	26, 770	8, 175	3
1985:							
	California	456, 000	48, 640	19, 885	39, 768	7, 800	0
	Northwest	(2)	5	25, 200	14, 073	3, 500	0
	Rocky Mountain	185, 000	1, 400	34, 539	1, 039	330	65
	Total	641, 000	50, 045	79, 624	54, 880	11, 630	65
1990:							
	California	456, 000	46, 020	27, 800	58, 900	9, 800	0
	Northwest	(2)	5	30, 600	30, 012	5, 180	0
	Rocky Mountain	268, 000	1, 400	40, 136	2, 728	660	100
	Total	724, 000	47, 425	98, 536	91, 640	15, 640	100

[1] Coal shown for California produced and used in Rocky Mountain Subregion.

[2] Negligible.

NOTE 1.—Except for ThO_2, which was separately estimated, nuclear fuel use in the Northwest and Rocky Mountain Regions was estimated at the same ratio to nuclear generation as for California.

NOTE 2.—Projected oil and coal use in the Northwest Region estimated from the corresponding electric generation, standard conversion factors for Btu content of fuels (Table 45) and heat rates (Table 6).

Sources of recorded data: Federal Power Commission, *Consumption of fuels for Electric Energy*, 1951, pages 10 & 14: *Electric Power Statistics*, 1955, 1956, 1960, 1961, 1965 and 1966, monthly; and FPC data in U.S. Bureau of Mines, *Minerals Yearbook*, 1955, 1960, 1965, and preprints therefrom. Nuclear fuel use computed from the efficiencies and net generation at Pacific Gas and Electric Company plants.

TABLE 10

Electric Generation, Percent Distribution by Energy Source, Electric Utility Industry, West Region, 1950–1990

[In percent]

Year	Thermal						Internal combustion	Hydro	Total
	Natural gas	Oil	Coal	Nuclear	Other [1]	Total			
Recorded:									
1950	13.6	6.7	1.2	0.0	0.5	22.0	0.5	77.5	100.0
1955	22.5	11.9	1.7	.0	.1	36.2	.3	63.5	100.0
1960	29.6	10.8	2.9	(2)	(2)	43.3	.3	56.4	100.0
1965	30.3	5.4	6.4	.1	.1	42.3	.2	57.5	100.0
Projected:									
1970	30.1	5.5	9.9	2.6	.2	48.3	.1	51.6	100.0
1975	20.3	7.9	18.0	14.1	.5	60.8	.1	39.1	100.0
1980	12.2	5.5	19.6	32.9	.6	70.8	.1	29.1	100.0
1985	7.8	3.6	19.1	46.8	.6	77.9	.1	22.0	100.0
1990	6.3	2.5	17.2	56.9	.5	83.4	.1	16.5	100.0

[1] Wood Waste, Geothermal and Other.

[2] Less than 0.05%.

Source: Table 7.

TABLE 11

Natural Gas Marketed Production, by States, West Region, 1946–66

[Billion Cubic Feet]

Year	California	Northwest			Rocky Mountain					Total, 11 western states	Non-western states	United States total
		Montana	Wyoming	Total [1]	Arizona	Colorado	New Mexico	Utah	Total [1]			
1946 [2]	488	31	33	64	0	7	119	4	130	682	3,349	4,031
1946 [3]	509	31	36	67	0	8	120	4	132	708	3,442	4,150
1947	561	34	46	80	0	8	143	6	157	798	3,784	4,582
1948	571	37	52	89	0	9	195	6	210	870	4,278	5,148
1949	551	35	51	86	0	8	205	6	219	856	4,564	5,420
1950	558	39	62	101	0	11	213	4	228	887	5,395	6,282
1951	567	36	72	108	0	14	300	4	318	993	6,464	7,457
1952	517	29	75	104	0	34	359	3	396	1,017	6,996	8,013
1953	531	28	76	104	0	29	399	7	435	1,070	7,327	8,397
1954	507	30	71	101	0	46	449	16	511	1,119	7,624	8,743
1955	538	28	78	106	(4)	49	541	17	607	1,251	8,154	9,405
1956	505	26	84	110	(4)	54	627	17	698	1,313	8,769	10,082
1957	492	29	117	146	0	95	723	17	835	1,473	9,207	10,680
1958	466	28	121	149	0	83	761	19	863	1,478	9,552	11,030
1959	485	31	157	188	0	100	740	39	879	1,552	10,494	12,046
1960	518	33	182	215	0	107	799	51	957	1,690	11,081	12,771
1961	556	34	195	229	0	108	790	57	955	1,740	11,514	13,254
1962	564	30	205	235	0	102	805	74	981	1,780	12,097	13,877
1963	646	30	209	239	1	106	809	77	993	1,878	12,869	14,747
1964	664	25	233	258	2	114	879	80	1,075	1,997	13,465	15,462
1965	660	28	236	264	3	126	937	72	1,138	2,062	13,978	16,040
1966	690	31	243	274	3	137	998	69	1,207	2,171	15,036	17,207

[1] None in Idaho, Nevada, Oregon, Washington.

[2] Reported.

[3] Adjusted to new basis to cover transmission losses and net to storage.

[4] Under 0.5 billion.

Source: U.S. Bureau of Mines, *Minerals Yearbook*, Annual; preprints therefrom; Mineral Industry Surveys, Natural Gas, 1966.

TABLE 12

Natural Gas Supply, West Region, 1946–66

[Billion cubic feet]

Year	Supply: Marketed production	Supply: Net imports, by source: Other U.S.	Supply: Net imports, by source: Canada	Supply: Net imports, by source: Total	Supply: Total supply	Deductions: Transmission losses and unaccounted for—	Deductions: Net additions to underground storage	Net supply consumed
1946.......	[1] 708	23	0	23	731	[2] 20	6	705
1947.......	798	30	0	30	828	[3] 22	([4])	806
1948.......	870	72	0	72	942	[3] 30	2	910
1949.......	856	149	0	149	1,005	[3] 48	4	953
1950.......	887	228	0	228	1,115	[3] 25	14	1,076
1951.......	993	275	0	275	1,268	[3] 39	−4	1,233
1952.......	1,017	282	8	290	1,307	[3] 35	11	1,261
1953.......	1,070	340	9	349	1,419	[3] 45	14	1,360
1954.......	1,119	353	7	360	1,479	[3] 37	9	1,433
1955.......	1,251	370	11	381	1,631	27	−1	1,605
1956.......	1,313	390	10	400	1,713	39	7	1,667
1957.......	1,473	402	21	423	1,896	29	17	1,850
1958.......	1,478	342	90	432	1,910	34	21	1,855
1959.......	1,552	479	83	562	2,114	54	9	2,051
1960.......	1,690	516	96	612	2,302	45	16	2,241
1961.......	1,740	608	108	716	2,456	54	−3	2,405
1962.......	1,780	551	288	839	2,619	60	42	2,517
1963.......	1,878	548	294	842	2,720	69	39	2,612
1964.......	1,997	638	317	955	2,952	66	23	2,863
1965.......	2,062	630	328	958	3,020	93	33	2,894
1966.......	2,171	609	[5] 355	964	3,135	86	−6	3,055

[1] Reported figure, 682 billion, adjusted to new basis, to cover deductions.
[2] Estimated from trends.
[3] Computed: total supply less net supply consumed and net additions to underground storage.
[4] Less than 0.5 billion cubic feet.
[5] Includes 3 billion from Mexico.

Source: U.S. Bureau of Mines, Minerals Yearbook, annual; preprints therefrom; Mineral Industry Surveys, Natural Gas, 1966.

TABLE 13

Natural Gas Requirements, by Type and Sub-region, 1946–90

[Billion cubic feet]

Year	Electric generation fuel				Other consumption				Net to underground storage, transmission loss, & unaccounted for—				Total Disappearance			
	California	Northwest	Rocky Mountain	Total west region	California	Northwest	Rocky Mountain	Total west region	California	Northwest	Rocky Mountain	Total west region	California	Northwest	Rocky Mountain	Total west region
Recorded:																
1946	19	1	16	36	469	50	150	669	21	3	2	26	509	54	168	731
1950	78	2	47	127	606	74	269	949	22	2	15	39	706	78	331	1,115
1955	184	2	93	279	836	85	405	1,326	25	−1	2	26	1,045	86	500	1,631
1960	323	2	134	459	988	231	563	1,782	45	14	2	61	1,356	247	699	2,302
1965	492	2	134	628	1,265	337	664	2,266	66	21	39	126	1,823	360	837	3,020
1966	597	3	151	751	1,288	368	648	2,304	4	26	50	80	1,889	397	849	3,135
Projected:																
1970	719	(1)	136	855	1,538	477	764	2,779	50	25	40	115	2,307	502	940	3,749
1975	641	(1)	161	802	1,812	675	895	3,382	60	25	45	130	2,513	700	1,100	4,313
1980	478	(1)	207	685	2,082	796	993	3,871	70	25	50	145	2,630	821	1,250	4,701
1985	456	(1)	185	641	2,257	891	1,150	4,298	75	25	55	155	2,788	916	1,390	5,094
1990	456	(1)	268	724	2,407	995	1,185	4,587	80	25	60	165	2,943	1,020	1,513	5,476

[1] Less than 0.5 billion cubic feet.

Source of actual data: U.S. Bureau of Mines, *Minerals Yearbook*, annual; preprints therefrom; Mineral Industry Surveys, Natural Gas Production and Consumption, 1966.

Source of projections: Total requirements, 11 Western States, projected on the basis of percentage changes of projections in Future Requirements Committee, Under the Auspices of the Gas Industry Committee, *Future Natural Gas Requirements of the United States*, Vol. 2, June 1967, Denver Research Institute, University of Denver, page 6. By starting the projections from the 1966 actual rather than estimated 1966 amount, an abrupt 16.9% increase for 1965–66 in the Denver estimate for the 11 Western States is reduced to a more normal 3.8%. Projections for later years start from this lower base. The effect is believed to be largely to exclude that part of interruptible requirements normally unmet due to curtailment. Such curtailment is expected by the customers concerned and it would be uneconomical for gas suppliers to install sufficient additional peaking capacity to assure avoidance of this normal curtailment. So only that curtailment beyond normal is considered here as a failure to meet requirements.

The above adjustment also prevents an abrupt drop in the percentage share of California in the 11 state total.

California total extrapolated to 1975 on basis of percentage changes of sendout plus net to storage from: *1967 California Gas Report*, prepared pursuant to Decision No. 62260, Case 5924, California Public Utilities Commission, Tables 1a–1c. To the latter the present figures in effect add field and other use included in U.S. Bureau of Mines figures. Normal curtailment is excluded. The remaining regional breakdown of total requirements is based in part on percentage changes in the Denver report for regions overlapping the regions here used. Electric generation requirements are from Table 9. The California and the 11 state total disappearance was adjusted up in 1970 and down in 1975, and by extrapolation thereafter, for the difference between electric generation requirements in Table 9 and those in Case 5924 report: 1970, 72 billion CF; 1975, 22 billion CF; 1980, 120 billion CF; 1985, 142 billion CF; 1990, 142 billion CF.

The 1990 total disappearance was reduced by 183 billion CF so that the 1985–90 increase would be reduced to 7.5% and so be less than the 8.4% for 1980–85. The future Requirements Committee figures for the 11 states showed an abrupt 10.8% increase for 1985–90.

TABLE 13–A

Percentage Changes in Natural Gas Requirements by Type and Sub-region, 1946–90

[In percent]

Year	Electric generation fuel				Other consumption				Net stored underground, transmission loss, and unaccounted for—				Total disappearance			
	California	North-west	Rocky Mountain	Total west region	California	Northwest	Rocky Mountain	Total west region	California	North-west	Rocky Mountain	Total west region	California	Northwest	Rocky Mountain	Total west region
Recorded:																
1946–50	310.5	[1]	193.7	252.8	27.9	48.0	79.7	41.9	[1]	[1]	[1]	[1]	38.7	44.5	97.0	52.5
1950–55	135.9	[1]	100.0	120.5	38.0	13.5	50.5	39.7	[1]	[1]	[1]	[1]	48.0	10.2	51.3	46.4
1955–60	75.5	[1]	42.5	64.5	18.2	171.8	39.0	34.4	[1]	[1]	[1]	[1]	29.8	187.2	39.5	41.1
1960–65	52.3	[1]	.0	36.8	28.0	45.9	17.9	27.2	[1]	[1]	[1]	[1]	34.4	45.9	19.7	31.2
Projected:																
1965–70	46.1	[1]	1.5	36.1	21.6	41.5	15.1	22.6	−24.2	19.0	2.6	−8.7	26.6	28.3	17.1	24.1
1970–75	−10.8	0.0	17.7	−6.2	17.8	41.5	17.1	21.7	20.0	.0	12.5	13.0	8.9	39.4	17.0	15.0
1975–80	25.4	.0	29.4	−14.6	14.9	17.9	10.9	14.5	16.7	.0	11.1	11.5	4.7	17.3	13.6	9.0
1980–85	−4.6	.0	10.6	−6.4	8.4	11.9	15.8	11.0	7.1	.0	10.0	6.9	6.0	11.6	11.2	8.4
1985–90	.0	.0	44.9	12.9	6.6	11.7	3.0	6.7	6.7	.0	9.1	6.5	5.6	11.4	8.9	7.5

[1] Not significant.

Source: Table 13.

TABLE 14

Natural Gas Available Proved Reserves and Requirements, West Region 1966–1990

[Trillions of cubic feet]

	Recorded	Projected				
	1966	1970	1975	1980	1985	1990
Reserves, end of year:						
U.S. total	[1] 289.3	[2] 300.0	[2] 310.0	[2] 305.0	[2] 295.0	[2] 260.0
Available to 11 Western States:						
In 11 Western States (10.5% of U.S.)	[1] 30.5	31.5	32.6	32.0	31.0	27.3
In Other U.S. (4.1% of U.S.[3])	11.7	12.3	12.7	12.5	12.1	10.7
Total available in United States (14.6% of U.S.)	42.2	43.8	45.3	44.5	43.1	38.0
Canada, Total	[1] 43.5	[4] 51.1	58.0	64.0	70.0	75.0
Available to 11 Western States (31.3% [5])	13.6	16.0	18.2	20.0	21.9	23.5
Total available to 11 Western States	55.8	59.8	63.5	64.5	65.0	61.5
Requirements, annual [6]	3.1	3.7	4.3	4.7	5.1	5.5
Reserves requirements:						
Indicated life of reserves available to 11 Western States, years	18.0	16.2	14.8	13.7	12.8	11.2

[1] American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1966*, pages 109 and 256.

[2] Approximates projection by H. R. Linden, Director, Institute for Gas Technology, "U.S. Natural Gas Supply and Demand," *Public Utilities Fortnightly*, Vol. 81, No. 3, Feb. 1, 1968, page 17.

[3] Based on share of marketed production in other U.S. imported net into the 11 Western States in 1966. Data source: U.S. Bureau of Mines, Mineral Industry Surveys, *Natural Gas Production and Consumption, 1966*, page 2.

[4] Craig, O. R., et al., Oil and Gas Conservation Board, Province of Alberta, Canada, "Oil and Gas Reserves in Western Canada," paper presented at Engineering Institute of Canada, Zone A Technical Conference, Edmonton, Sept. 12–14, 1962, page 10. Reduced 7.1% to marketable basis.

[5] Share of Canadian marketed production received in 1966. Data Source: U.S. Bureau of Mines, *op. cit.*, page 2.

[6] Table 13.

TABLE 15

Estimated Ultimate Natural Gas Supply Available to the West Region

[Trillions of cubic feet]

	Low	Medium	High
1. U.S. ultimate cumulative recovery	998	[1] 1,740	[2] 2,000
2. Less past production through 1966 [3]	308	308	308
3. U.S. ultimate future recovery	[4] 690	1,432	1,692
4. Dec. 31, 1966, proved recoverable sererves [5]	289	289	289
5. Future discoveries	401	1,143	1,403
6. Total future recovery (=line 3)	690	1,432	1,692
7. Future recovery available to 11 Western States:			
8. In 11 Western States	[4] 105	[6] 150	[6] 178
9. From other U.S.	[7] 24	[7] 53	[7] 62
10. Total from U.S. sources (14.6% of U.S. total)	129	203	240
11. Canadian ultimate future recovery	[8] 250	[9] 300	[10] 350
12. Percent available to 11 Western States	30.0%	[11] 31.3%	33.3%
13. Amount available to 11 Western States	75	94	117
14. Total future availability to 11 Western States (lines 10 & 13)	204	297	357
15. Equals roughly projected requirements through the year	2,005	2,020	2,030

[1] Linden, H. R., Director, Institute for Gas Technology, "U.S. Natural Gas Supply and Demand," *Public Utilities Fortnightly*, vol. 81, No. 3, Feb. 1, 1968, page 17.

[2] Hendricks, T. A., *Resources of Oil, Gas and Natural—Gas Liquids in the United States and the World*, U.S. Geological Survey, Circular 522, 1965, reprinted 1966, page 12.

[3] Production of 230 trillion cubic feet through 1961, given by Hendricks, page 12, plus 78 trillion produced during 1962–1966, given by U.S. Bureau of Mines, Mineral Industry Surveys, *Natural Gas*, annual.

[4] Potential Gas Committee, *Potential Supply of Natural Gas in the United States as of December 31, 1966*, sponsored by Potential Gas Agency, Mineral Resources Institute, Colorado School of Mines Foundation, Inc., pages 8–9. Included probable, possible and speculative amounts.

[5] American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1966*, page 109.

[6] Estimated at 10.5% of U.S. total, based on share of December 31, 1966, reserves in *ibid.*, page 109.

[7] Estimated at 4.1% of other U.S. availability, based on share of marketed production in other U.S. imported net into the 11 Western States in 1966. Data Source: U.S. Bureau of Mines, Mineral Industry Surveys, *Natural Gas Production and Consumption*, 1966, page 2.

[8] Craig, D. R., et al., Oil and Gas Conservation Board, Province of Alberta, Canada, "Oil and Gas Reserves in Western Canada," paper presented at Engineering Institute of Canada, Zone A Technical Conference, Edmonton, September 12–14, 1962, page 10.

[9] Stalbach, J. G., Chief Engineer, National Energy Board, Canada, as quoted in the *Oil and Gas Journal*, vol. 64, No. 39, September 26, 1966, page 57. Allowance of 8 trillion cubic feet is added for omitted areas, the Arctic Islands and Continental Shelves. Cumulative production through 1966 is deducted.

[10] Estimate based in part on statement by Stalbach, *op. cit.*, page 57, that ultimate reserves, including the Arctic Islands and Continental Shelves, could be substantially greater than the 300 trillion cubic feet now estimated.

[11] Share of Canadian marketed production received in 1966. Data Source: U.S. Bureau of Mines, Mineral Industry Surveys, *Natural Gas Production and Consumption*, 1966, page 2.

TABLE 16

Estimated Natural Gas From All Sources Available to the Eleven Western States, 1966–1990

[Trillions of cubic feet]

Year end	Total ultimate future recovery [1]	Recoverable gas available to the eleven western states: Less cumulative consumption	Remaining in the ground: Total	Remaining in the ground: Undiscovered or unproved	Remaining in the ground: Proved recoverable reserves [3]	5-year total: Gross additions to proved recoverable reserves	5-year total: Less consumption [2]	5-year total: Net change in proved recoverable reserves
1966	297	0	297.0	241.2	55.8			
1970	297	13.8	283.2	223.4	59.8	[4] 17.8	[4] 13.8	[4] 4.0
1975	297	33.9	263.1	199.6	63.5	23.8	20.1	3.7
1980	297	56.4	240.6	176.1	64.5	23.5	22.5	1.0
1985	297	80.9	216.1	151.1	65.0	25.0	24.5	.5
1990	297	107.3	189.7	128.2	61.5	22.9	26.4	−3.5

[1] Table 15, Line 14, Medium Estimate.

[2] Based on Table 13, interpolating for years not shown.

[3] Represents 14.6% of U.S. reserves plus 31.3% of Canadian reserves, in accordance with Medium Estimate, Table 15, lines 10 and 12; and also Table 14.

[4] Four years.

TABLE 17

Estimated Proved Recoverable Reserves of Natural Gas

[Billion cubic feet]

Year end	California	Northwest				Rocky Mountain						Total, west region	Non-western States	United States, total
		Montana	Washington	Wyoming	Total [1]	Arizona	Colorado	Nevada	New Mexico	Utah	Total			
1945	10,856	1,203	0	817	2,020	0	396	0	5,190	(2)	5,586	18,402	129,327	147,789
1946	11,126	853	0	1,036	1,889	0	316	0	5,905	(2)	6,221	19,236	141,340	160,576
1947	10,164	701	0	1,192	1,893	0	332	0	5,990	67	6,389	18,446	147,481	165,927
1948	10,193	853	0	2,094	2,947	0	1,349	0	5,606	70	7,025	20,165	153,704	173,869
1949	9,992	803	0	2,174	2,977	0	1,227	0	6,241	66	7,534	20,503	159,878	180,381
1950	9,760	797	0	2,195	2,992	0	1,115	0	6,991	85	8,191	20,943	164,650	185,593
1951	9,482	828	0	2,340	3,168	0	1,138	0	11,590	96	12,824	25,474	168,337	193,811
1952	9,340	828	0	2,321	3,149	0	1,164	0	14,039	283	15,486	27,975	171,741	199,716
1953	9,159	764	0	2,740	3,504	0	1,864	0	17,522	1,113	19,499	32,162	178,285	211,447
1954	9,027	724	0	2,855	3,579	(2)	1,933	0	17,241	387	19,561	32,167	179,544	211,711
1955	8,893	720	0	3,196	3,916	(2)	2,254	(2)	18,585	421	21,260	34,069	189,628	223,697
1956	8,751	696	0	3,236	3,932	(2)	2,423	(2)	23,473	620	26,516	39,199	198,576	237,775
1957	8,953	670	0	3,457	4,127	(2)	2,381	(2)	22,258	859	25,498	38,578	207,991	246,569
1958	8,967	682	0	3,650	4,332	0	2,349	0	21,180	1,058	24,587	37,886	261.256	254,142
1959	8,593	665	0	3,847	4,512	(2)	2,496	0	17,913	1,264	21,673	34,778	227,819	262,597
1960	8,844	626	0	3,935	4,561	(2)	2,043	0	15,604	1,526	19,173	32,578	231,181	263,759
1961	9,104	596	0	4,127	4,723	(2)	2,171	0	14,758	2,030	18,801	32,628	234,942	267,728
1962	9,121	600	0	3,931	4,531	(2)	2,205	0	14,113	1,786	18,104	31,756	240,523	272,279
1963	8,866	598	(2)	3,989	4,587	(2)	1,876	0	15,038	1,638	18,452	31,905	244,146	276,151
1964	9,054	590	(2)	3,769	4,359	(2)	1,729	0	15,354	1,519	18,602	32,015	249,236	281,251
1965	8,832	596	(2)	3,703	4,299	(2)	1,718	0	15,375	1,439	18,532	31,663	254,806	286,469
1966	8,474	620	(2)	3,594	4,214	(2)	1,651	0	14,753	1,372	17,776	30,464	258,869	289,333

[1] None in Idaho, Oregon. [2] Under 0.5 billion.

Source: Amer. Gas Assn., Amer. Petr. Inst., Canadian Petr. Assn. *Reserves of Crude Oil, Nat. Gas Liquids, and Nat. Gas.* Annual.

TABLE 18

New Discoveries Initially Included in Estimated Proved Recoverable Reserves of Natural Gas, 1947–66

[Billion cubic feet]

Year	California	Northwest			Rocky Mountain				Total west region	Non-western States	United States, total
		Montana	Wyoming	Total [1]	Colorado	New Mexico	Utah	Total [1]			
1947	58	49	41	90	15	311	0	326	474	2,936	3,410
1948	111	2	588	590	408	109	10	527	1,228	2,901	4,129
1949	188	4	108	112	5	146	(2)	151	451	4,162	4,613
1950	72	0	3	3	41	124	15	180	255	2,622	2,877
1951	67	0	67	67	25	132	6	163	297	2,742	3,039
1952	66	17	21	38	42	217	3	262	366	5,045	5,411
1953	50	1	24	25	213	301	13	527	602	6,480	7,082
1954	59	23	229	252	174	550	8	732	1,043	3,924	4,967
1955	73	17	113	130	73	254	50	377	580	5,139	5,719
1956	76	1	17	18	73	340	47	460	554	5,082	5,636
1957	145	1	114	115	55	216	65	336	596	8,403	8,999
1958	57	38	176	214	53	175	2	230	501	5,110	5,611
1959	56	14	145	159	26	196	74	396	611	5,190	5,801
1960	325	0	94	94	122	127	64	313	732	5,905	6,637
1961	268	7	134	141	56	50	93	199	608	6,337	6,945
1962	223	5	59	64	20	109	35	164	451	5,883	6,334
1963	106	2	27	29	24	91	20	135	270	5,308	5,578
1964	142	2	70	72	18	86	12	116	330	6,579	6,909
1965	108	(2)	96	96	18	79	8	105	309	6,235	6,544
1966	37	23	32	55	9	44	314	367	459	5,599	6,058

[1] None in Idaho, Oregon; negligible in Arizona, Nevada, Washington.
[2] Under 0.5 billion.

Source: Amer. Gas Assn., Amer. Petr. Inst., Canadian Petr. Assn., *Reserves of Crude Oil, Nat. Gas Liquids, and Nat. Gas*, Annual.

TABLE 19

Revisions and Extensions of Estimated Proved Recoverable Reserves of Natural Gas in Previously Discovered Fields, 1947–66

[Billion cubic feet]

Year	California	Northwest			Rocky Mountain				Total west region	Non-western States	United States, total
		Montana	Wyoming	Total [1]	Colorado	New Mexico	Utah	Total [1]			
1947	−460	−166	165	−1	12	6	(2)	18	−443	8,014	7,571
1948	499	189	363	552	622	−215	0	407	1,458	8,311	9,769
1949	152	−17	44	27	−102	738	2	638	817	7,244	8,061
1950	225	35	97	132	−134	867	8	741	1,098	8,074	9,172
1951	171	69	161	230	23	4,786	9	4,818	5,219	7,795	13,014
1952	269	13	36	49	32	2,669	188	2,889	3,207	5,727	8,934
1953	219	−51	481	430	543	3,540	827	4,910	5,559	7,812	13,371
1954	288	−31	−27	−58	−50	−331	−717	−1,098	−868	5,500	4,632
1955	305	11	351	362	317	1,621	2	1,940	2,607	13,691	16,298
1956	258	6	152	158	188	5,223	170	5,581	5,997	13,218	19,215
1957	516	1	261	262	40	−685	192	−453	325	10,793	11,118
1958	378	(2)	154	154	47	−529	234	−248	284	13,105	13,389
1959	39	−3	255	252	236	−2,759	176	−2,347	−2,056	10,989	14,933
1960	395	−17	200	183	−475	−1,654	260	−1,869	−1,291	8,624	7,333
1961	518	1	328	329	167	−150	467	484	1,331	8,984	10,315
1962	362	4	−18	−14	112	54	−190	−24	324	12,933	13,257
1963	226	11	243	254	−260	1,563	−100	1,203	1,683	11,120	12,803
1964	672	7	−54	−47	−64	1,017	66	987	1,612	11,731	13,343
1965	279	24	101	125	82	880	−25	937	1,341	13,435	14,776
1966	329	20	124	144	53	337	−11	379	852	13,311	14,163

[1] None in Idaho, Oregon; negligible in Ariz., Nev., Wash.
[2] Under 0.5 billion.

Source: Amer. Gas Assn., Amer. Petr. Inst., Canadian Petr. Assn., *Reserves of Crude Oil, Nat. Gas Liquids, and Nat. Gas*, Annual.

TABLE 20

Residual Fuel Oil Supply and Demand Factors, West Region, 1950–1990

[Amounts in millions of barrels]

Year	Residual Fuel Oil—New Supply				Stock change	Sales			All petroleum products			
									Refinery output		Sales	
	New refinery output	Crude oil used as residual oil	Apparent net imports or exports (—)	Total		Total	Regular	Low sulfur	Total	Percent residual fuel oil yield	Total	Percent residual fuel oil
Recorded:												
1950	134	2	−30	106	−17	123	123		422	31.8	[1] 390	31.6
1955	145	3	−43	105	−18	123	123		519	28.0	[1] 501	24.6
1960	116	1	−20	97	−8	105	105		576	20.1	[1] 570	18.4
1965	115	2	−13	104	11	93	93		679	16.9	657	14.2
1966	116	1	−13	104	2	102	102		682	17.0	[1] 695	14.7
Projected:												
1970	95		−5	90		90	70	20	742	12.8	742	12.1
1975	50		60	110		110	55	55	827	6.0	827	13.3
1980	35		70	105		105	45	60	898	3.9	898	11.7
1985	20		80	100		100	40	60	943	2.1	943	10.6
1990	10		85	95		95	35	60	985	1.0	985	9.6

[1] Partly estimated.

Data Sources: U.S. Bureau of Mines, *Minerals Yearbook*, annual: *Mineral Industry Surveys*, annual, entitled: *Crude Petroleum and Petroleum Products; Fuel Oil;* and *Petroleum Situation in District V.*

TABLE 21

Residual Fuel Oil Supply by Type of Use, West Region,[1] 1951–1966

[Thousands of barrels]

Year	Competitive with gas					Year	Noncompetitive with gas					Total sales
	Electric generation	Industrial[2]	Oil company use[3]	Space heating	Subtotal		Railroad	Vessels, civilian	Military	Other[4]	Subtotal	
1951	21,237	19,580	9,727	8,878	59,422	1951	26,338	25,277	18,879	2,403	72,897	132,319
1952	19,282	22,080	10,587	10,193	62,142	1952	22,436	26,461	14,142	2,400	65,439	127,581
1953	24,137	20,901	8,515	9,370	62,923	1953	17,404	31,346	13,591	2,343	64,684	127,607
1954	17,619	21,551	11,924	9,221	60,315	1954	11,505	27,782	14,834	2,540	56,661	116,976
1955	24,978	22,756	12,625	11,525	71,884	1955	10,494	25,132	12,677	3,018	51,321	123,205
1956	27,353	24,643	9,783	11,972	73,751	1956	5,886	27,107	12,927	3,019	48,939	122,690
1957	27,003	17,471	8,312	11,234	64,020	1957	2,885	30,203	9,636	2,988	45,712	109,732
1958	18,437	14,031	10,711	9,344	52,523	1958	3,000	25,832	13,428	2,625	44,885	97,408
1959	20,018	12,208	10,616	9,431	52,273	1959	3,207	28,808	12,192	1,885	46,092	98,365
1960	25,813	14,105	9,332	11,664	60,914	1960	2,795	29,308	10,391	1,781	44,275	105,189
1961	25,075	14,810	8,156	11,959	60,000	1961	2,155	30,328	14,404	1,416	48,303	108,303
1962	19,511	15,789	9,361	12,151	56,812	1962	2,214	22,787	13,853	1,608	40,462	97,274
1963	16,759	14,125	10,881	12,886	54,651	1963	1,702	18,970	13,059	1,412	35,143	89,794
1964	16,189	15,995	11,894	11,521	55,599	1964	2,115	23,172	11,796	1,907	38,990	94,589
1965	18,097	14,571	10,514	9,974	53,156	1965	2,477	19,972	15,725	1,922	40,096	93,252
1966	21,649	16,496	11,208	9,657	59,010	1966	2,160	19,444	19,204	1,852	42,660	101,670

[1] Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming.
[2] Manufacturing, mines, smelters.
[3] Including small amounts of acid sludge and crude oil.
[4] Trucks, dredges, dust control, sprays, orchard heating, etc.

Source: U.S. Bureau of Mines, *Mineral Industry Surveys, Fuel Oil*, annual; *A Quarter Century of Fuel Oil Sales, 1926–50*, Info. Circ. 7630, January 1952.

TABLE 22

Crude Petroleum Production in Relation to Petroleum Product Sales, 11 Western States, 1946–1966

[Millions of barrels]

Year	Crude petroleum production						
	California	Northwest region					
		Idaho	Montana	Oregon	Washington	Wyoming	Total
1946	315	0	9	0	0	39	48
1950	328	0	8	0	0	62	70
1955	355	0	16	0	(1)	99	115
1960	305	0	30	0	(1)	134	164
1965	316	0	33	0	0	138	171
1966	345	0	35	0	(1)	134	169

Year	Rocky Mountain region						Total, 11 Western States
	Arizona	Colorado	Nevada	New Mexico	Utah	Total	
1946	0	12	0	37	0	49	412
1950	0	23	0	47	1	71	469
1955	0	53	(1)	83	2	138	608
1960	(1)	47	(1)	107	38	192	661
1965	(1)	34	(1)	119	25	178	665
1966	(1)	33	(1)	124	24	181	695

Year	Crude petroleum and petroleum products, 11 Western States			
	Apparent net imports or exports(−)	Stock change	Petroleum product sales	Percent self-sufficient [2]
1946	−92	[3] 0	[3] 320	[3] 128.8
1950	−79	[3] 0	[3] 390	[3] 120.2
1955	−133	[3] −26	[3] 501	[3] 121.4
1960	−78	13	[3] 570	[3] 116.0
1965	7	15	657	101.2
1966	3	3	[3] 695	[3] 100.0

[1] Negligible.

[2] Crude Petroleum production/petroleum product sales.

[3] Partly estimated.

Data Sources: U.S. Bureau of Mines, *Minerals Yearbook*, annual; Mineral industry Surveys, annual; *Crude Petroleum and Petroleum Products;* and *Petroleum Situation in District 5.* And Table 3.

TABLE 23

Estimated Proved Reserves of Crude Petroleum and Natural Gas Liquids, 1946–66

[Million barrels]

Yearend	California	Northwest			Rocky Mountain				Total west region	Non-Western States	United States total
		Montana	Wyoming	Total [1]	Colorado	New Mexico	Utah	Total [1]			
1946	3,602	113	615	728	302	617	(2)	919	5,249	18,788	24,037
1947	3,607	116	689	805	390	616	(2)	1,006	5,418	19,324	24,742
1948	4,071	123	752	875	402	632	(2)	1,034	5,980	20,841	26,821
1949	4,143	116	735	851	369	678	16	1,063	6,057	22,322	28,379
1950	4,097	115	890	1,005	352	686	22	1,060	6,162	23,374	29,536
1951	4,090	112	1,019	1,131	337	742	30	1,109	6,330	25,863	32,193
1952	4,177	159	1,122	1,281	317	885	42	1,244	6,702	26,255	32,957
1953	4,244	212	1,330	1,542	330	1,136	38	1,504	7,290	27,093	34,383
1954	4,219	280	1,354	1,634	341	1,146	36	1,523	7,376	27,429	34,805
1955	4,126	306	1,424	1,730	347	1,162	37	1,546	7,402	28,049	35,451
1956	4,083	340	1,417	1,757	375	1,250	62	1,687	7,527	28,810	36,337
1957	4,065	328	1,471	1,799	321	1,152	140	1,613	7,477	28,511	35,988
1958	4,169	345	1,460	1,805	413	1,311	214	1,938	7,912	28,828	36,740
1959	4,088	323	1,476	1,799	406	1,449	227	2,082	7,969	30,273	38,242
1960	3,972	278	1,524	1,802	388	1,568	259	2,215	7,989	30,440	38,429
1961	3,949	262	1,481	1,743	440	1,591	269	2,300	7,992	30,816	38,808
1962	3,948	259	1,398	1,657	410	1,582	247	2,239	7,844	30,857	38,701
1963	3,890	281	1,354	1,635	390	1,569	266	2,225	7,750	30,894	38,644
1964	4,398	265	1,297	1,562	372	1,533	274	2,179	8,139	30,598	38,737
1965	4,830	284	1,263	1,547	351	1,438	248	2,037	8,414	30,962	39,376
1966	4,850	292	1,159	1,451	369	1,584	256	2,209	8,510	31,271	39,781

[1] None in Idaho, Ore.; negligible in Ariz., Nev., Wash.

[2] Under 0.5 million.

Source: Amer. Gas Assn., Amer. Petr. Inst., Canadian Petr. Assn., *Reserves of Crude Oil, Nat. Gas Liquids, and Nat. Gas*, Annual.

TABLE 24

New Discoveries Initially Included in Estimated Proved Reserves of Crude Petroleum and Natural Gas Liquids, 1947–66

[Million barrels]

Year	California	Northwest			Rocky Mountain				Total west region	Non-Western States	United States total
		Montana	Wyoming	Total [1]	Colorado	New Mexico	Utah	Total [1]			
1947	14	3	11	14	(2)	3	0	3	31	474	505
1948	60	2	22	24	1	12	(2)	13	97	364	461
1949	176	(2)	12	12	(2)	42	1	43	231	752	983
1950	11	(2)	22	22	3	14	(2)	17	50	573	623
1951	7	2	23	25	2	10	6	18	50	415	465
1952	45	27	16	43	8	24	1	33	121	457	578
1953	21	3	9	12	34	15	(2)	49	82	606	688
1954	29	2	24	26	28	12	(2)	40	95	577	672
1955	31	5	8	13	19	10	(2)	29	73	471	544
1956	20	8	7	15	5	24	27	56	91	470	561
1957	16	1	11	12	3	16	22	41	69	476	545
1958	16	5	8	13	6	16	1	23	52	371	423
1959	9	3	5	8	3	21	(2)	24	41	438	479
1960	11	6	9	15	2	23	1	26	52	323	375
1961	22	4	18	22	1	28	2	31	75	391	466
1962	4	2	17	19	2	23	1	26	49	484	533
1963	12	4	12	16	2	20	(2)	22	50	478	528
1964	41	6	15	21	4	7	5	16	78	419	497
1965	50	2	20	22	2	8	1	11	83	500	583
1966											

[1] None in Idaho, Ore.; negligible in Ariz., Nev., Wash.

[2] Under 0.5 million.

Source: Amer. Gas Assn., Amer. Petr. Inst., Canadian Gas Assn., *Reserves of Crude Oil, Nat. Gas Liquids, and Nat. Gas.*, Annual.

TABLE 25

Revisions and Extensions of Estimated Proved Reserves of Crude Petroleum and Natural Gas Liquids in Previously Discovered Fields, 1947–66

[Million barrels]

Year	California	Northwest			Rocky Mountain				Total west region	Non-Western States	United States total
		Montana	Wyoming	Total [1]	Colorado	New Mexico	Utah	Total [1]			
1947	350	10	108	118	103	41	([2])	144	612	1, 599	2, 211
1948	771	15	99	114	28	55	([2])	83	968	2, 837	3, 805
1949	256	3	20	23	−3	55	15	67	346	2, 246	2, 592
1950	299	7	195	202	4	43	7	54	555	2, 151	2, 706
1951	370	4	177	181	11	108	3	122	673	4, 000	4, 673
1952	430	30	158	188	2	188	13	203	821	1, 907	2, 728
1953	442	62	284	346	15	317	−3	329	1, 117	2, 235	3, 352
1954	333	80	92	172	30	85	([2])	115	620	1, 688	2, 308
1955	262	37	165	202	39	102	3	144	608	2, 233	2, 841
1956	318	48	96	144	83	166	([2])	249	711	2, 512	3, 223
1957	335	15	156	171	−1	−6	62	55	561	1, 456	2, 017
1958	429	41	97	138	136	256	97	489	1, 056	1, 987	3, 043
1959	247	5	142	147	40	238	54	332	726	3, 165	3, 891
1960	206	−19	176	157	31	229	70	330	693	2, 022	2, 715
1961	281	11	88	99	104	135	42	281	661	2, 226	2, 887
1962	317	28	45	73	13	102	8	123	513	1, 868	2, 381
1963	255	50	85	135	21	104	55	180	570	1, 954	2, 524
1964	792	8	76	84	16	101	33	150	1, 026	1, 750	2, 776
1965	722	51	93	144	13	42	([2])	55	921	2, 377	3, 298
1966	378	44	32	76	49	291	31	371	825	2, 594	3, 419

[1] None in Idaho, Oreg.: negligible in Ariz., Nev., Wash.
[2] Under 0.5 million.
Source: Amer. Gas Assn., Amer. Petr. Inst., and Canadian Petr. Assn., *Reserves of Crude Oil, Nat. Gas Liquids, and Nat. Gas*, annual.

TABLE 26

Coal Production, West Region, 1946–1966

[Thousands of short tons]

Year	Colorado	Montana	New Mexico	Utah	Washington	Wyoming	Total
1946	5, 914	3, 520	1, 280	5, 994	991	7, 635	25, 334
1947	6, 358	3, 178	1, 443	7, 429	1, 118	8, 051	27, 577
1948	5, 631	2, 815	1, 364	6, 813	1, 220	6, 412	24, 255
1949	4, 636	2, 690	1, 004	6, 160	899	6, 001	21, 390
1950	4, 259	2, 512	727	6, 670	874	6, 348	21, 390
1951	4, 103	2, 370	783	6, 136	857	6, 430	20, 679
1952	3, 623	2, 010	760	6, 140	844	6, 088	19, 465
1953	3, 575	1, 802	514	6, 544	690	5, 245	18, 370
1954	2, 900	1, 495	123	5, 008	619	2, 831	12, 976
1955	3, 568	1, 212	201	6, 296	610	2, 927	14, 814
1956	3, 502	846	158	6, 522	473	2, 553	14, 054
1957	3, 594	413	137	6, 858	360	2, 117	13, 479
1958	2, 974	305	117	5, 328	752	2, 629	12, 105
1959	3, 294	345	148	4, 545	242	1, 977	10, 551
1960	3, 607	313	295	4, 955	228	2, 024	11, 422
1961	3, 678	371	412	5, 159	191	2, 519	12, 330
1962	3, 379	382	677	4, 297	235	2, 569	11, 539
1963	3, 690	343	1, 945	4, 360	190	3, 124	13, 652
1964	4, 355	346	2, 969	4, 720	68	3, 101	15, 559
1965	4, 990	375	3, 200	5, 100	59	3, 225	16, 949
1966	5, 222	419	2, 755	4, 635	59	3, 670	16, 760
Total							354, 650

Source: U.S. Bureau of Mines—Minerals Yearbook—1966.

TABLE 27

Coal Consumption, Eleven Western States, 1956–1966

[Thousands of short tons]

Year	Arizona	California	Colorado	Montana [1]	New Mexico	Nevada	Utah	Washington [2]	Wyoming
1956		1,886							
1957	145	1,820	3,264		92		3,748	1,324	607
1958	132	1,285	2,738		98		3,003	958	510
1959	109	1,497	2,781		113		2,508	897	894
1960	143	1,318	2,887	952	171		3,377	953	1,006
1961	133	2,170	3,242	1,045	138		3,046	992	1,328
1962	[3] 244	1,426	3,340	1,108	107	244	2,417	964	1,438
1963	261	1,690	3,752	1,066	1,132	261	2,334	828	1,977
1964	289	2,015	3,877	1,190	2,169	289	2,706	774	1,936
1965	361	2,378	4,500	1,075	2,505	361	2,868	798	2,196
1966	369	1,888	4,705	995	2,084	369	2,974	687	2,601

[1] Idaho included with Montana.
[2] Oregon included with Washington.
[3] Arizona and Nevada approximately equal. Principally coal-fired electric generation plants.
Source: U.S. Bureau of Mines—Minerals Yearbook—1966.

TABLE 28

Estimated Recoverable Coal Reserves, by Type, West Region, January 1, 1967,[1] 50% Recovery Assumed

[Millions of short tons]

State	Bituminous	Subbituminous	Lignite	Anthracite and semianthracite	Total	Economically recoverable from large deposits
Arizona	365	840			1,205	[2] 300
California [3]	5	19	23		47	
Colorado	31,195	9,125		39	40,359	[4] 16,750
Idaho [3]	299	([5])	([5])		299	
Montana	1,145	65,938	43,762		110,845	[4] 11,300
Nevada						
New Mexico	5,380	25,357		2	30,739	[4] 4,820
Oregon	24	142			166	
Utah	16,050	75			16,125	[4] 6,331
Washington	934	2,097	58	2	3,091	[2] 506
Wyoming	6,349	54,005	([5])		60,354	[4] 10,577
Total—11 Western States	61,746	157,598	43,843	43	263,230	50,564
Total—other States	273,781	56,507	179,780	6,441	516,710	[4] 128,294
Total—United States	335,527	214,105	223,623	6,484	779,940	178,858

Source except as noted:
[1] Paul Averitt, U.S. Geological Survey—Open File Report, 1968.
[2] Exhibit 89, Area Rate Case AR 61-1, Federal Power Commission Dec. 1961—Table 1 by Clayton G. Ball.
[3] Bulletin 1136 Coal Reserves of the United States—A progress Report, January 1, 1960.
[4] Based in part on unpublished information.
[5] Small; included with bituminous.

TABLE 29

Area Underlain by Coal, Selected States, 1960

State	Square miles		Percent underlain by coal
	Total area	Area underlain by coal	
Arizona	113, 909	3, 040	2. 7
California	158, 693	230	0. 1
Colorado	104, 247	29, 600	28. 4
Idaho	83, 557	500	0. 6
Montana	147, 138	51, 300	35. 0
Nevada	110, 540	50	0. 05
New Mexico	121, 666	14, 650	12. 0
Oregon	96, 981	600	0. 6
Utah	84, 916	15, 000	17. 7
Washington	68, 192	1, 150	1. 7
Wyoming	97, 914	40, 055	40. 9
Total, 11 States	1, 187, 753	156, 175	12. 8
39 other States	1, 988, 195	324, 175	16. 3
U.S. total	3, 175, 948	480, 350	13. 0

Source: U.S. Geological Survey, *Coal Reserves of the United States—A Progress Report, January 1, 1960*. Bulletin 1136, p. 27.

TABLE 30

Coal Production Per Man-Day, Selected States, 1946–1966

[Short tons per man-day]

Year	Arizona	Colorado	Montana	New Mexico	Utah	Washington	Wyoming	U.S. average
1946	2. 29	5. 18	14. 70	4. 14	3. 58	5. 47	3. 00	3. 44
1947	2. 48	5. 11	15. 28	5. 38	7. 00	3. 68	7. 92	6. 42
1948	2. 33	5. 23	15. 93	4. 95	6. 72	4. 13	7. 83	6. 26
1949	2. 27	5. 40	16. 59	4. 94	6. 57	3. 89	8. 17	6. 43
1950	2. 18	5. 48	17. 17	5. 32	7. 30	3. 96	8. 69	6. 77
1951	2. 28	5. 49	16. 61	5. 30	7. 41	4. 25	9. 72	7. 04
1952	2. 34	6. 06	18. 09	4. 93	7. 75	4. 30	10. 27	7. 47
1953	2. 72	6. 34	22. 71	5. 30	7. 48	4. 59	10. 21	8. 17
1954	3. 28	7. 05	[1] 23. 16	4. 25	9. 13	4. 88	13. 26	9. 47
1955	2. 78	6. 32	18. 54	4. 28	9. 75	5. 24	15. 34	9. 84
1956	2. 72	6. 29	13. 13	3. 97	10. 15	5. 19	15. 27	10. 28
1957	2. 52	6. 44	9. 39	3. 34	10. 27	5. 17	16. 55	10. 59
1958	2. 77	7. 42	9. 02	2. 76	10. 17	5. 22	19. 61	11. 33
1959	2. 68	8. 71	10. 62	3. 43	10. 18	3. 85	22. 83	12. 22
1960	2. 02	9. 34	13. 01	7. 27	10. 71	6. 46	23. 93	12. 83
1961	N.A.	10. 82	16. 04	9. 17	11. 63	5. 62	31. 05	13. 87
1962	N.A.	10. 89	21. 26	16. 62	12. 47	5. 40	30. 79	14. 72
1963	N.A.	12. 76	26. 70	32. 50	14. 76	4. 99	45. 11	15. 83
1964	N.A.	13. 29	26. 04	44. 18	13. 98	5. 53	45. 50	16. 84
1965	N.A.	14. 32	24. 33	49. 13	15. 74	6. 93	44. 69	17. 50
1966	N.A.	15. 68	23. 37	43. 46	15. 93	3. 22	49. 07	18. 15

[1] Bituminous only.

Source: U.S. Bureau of Mines, *Minerals Yearbook*, 1946–66, and Chapter preprints therefrom.

TABLE 31

Nuclear Electric Capacity and Generation, 1960–1990, West Region

	Nuclear reactor capacity, megawatts				Megawatt days thermal basis, thousand mwdt	Annual fuel use equivalent Btu input, trillion	[1]Capacity; factor, electric basis, percent	Annual generation, million kwh
	Thermal basis, mwt		Electric basis					
	Increase	Cumulative	Increase	Cumulative				
Year Recorded:								
1960	20	20	5	5	(2)	(2)	(2)	(2)
1965	145	165	45	50	37	3	61	270
Projected:								
1970	2, 735	3, 980	1, 220	1, 270	1, 062	82	[3] 73	8, 081
1975	26, 200	30, 180	8, 490	9, 760	8, 042	591	73	62, 652
1980	66, 335	96, 515	21, 275	31, 032	26, 770	1, 966	76	207, 695
1985	101, 320	197, 835	31, 175	62, 207	54, 880	3, 987	76	414, 150
1990	146, 070	343, 905	44, 945	107, 152	91, 640	6, 690	73	685, 200

[1] Derived from estimate of installed nuclear capacity and annual generation.
[2] Negligible.
[3] Includes Hanford at 66% capacity factor.

TABLE 32

Fuel Requirements for Nuclear Electric Generation, 1960–1990, West Region

[Short tons, including start-up inventory]

	Without recycle	With U–235 recycle at some plants	With Pu recycle at some plants	With U–233 recycle and ThO_2 at some plants	Total U_3O_8	Cumulative Total U_3O_8, 1968 on	ThO_2 used with U–233 recycle
Year Recorded:							
1960	(1)				(1)		
1965	14				14		
1966	8				8		
1967	399				399		
Projected:							
1968	20				20	20	
1969	148				148	168	
1970	1, 088	1, 027			1, 027	1, 195	
1971	872	825			825	2, 020	25
1972	1, 043	996			996	3, 016	
1973	1, 742	1, 742			1, 742	4, 758	3
1974	2, 040	2, 000			2, 000	6, 758	3
1975	3, 963	3, 625	3, 590		3, 590	10, 348	3
1976	5, 250	4, 640	4, 031		4, 031	14, 379	3
1977	5, 800	5, 568	4, 790		4, 790	19, 169	3
1978	6, 257	6, 010	5, 169		5, 169	24, 338	3
1979	7, 785	7, 473	6, 427	6, 420	6, 420	30, 758	3
1980	9, 915	9, 518	8, 185	8, 175	8, 175	38, 933	3
1981–1985	67, 580	64, 945	55, 920	55, 880	55, 880	94, 813	65
1986–1990	105, 225	101, 414	87, 950	87, 950	87, 700	87, 700	100

[1] Negligible.

NOTE.—Table assumes general use of light water reactors. If high temperature gas reactors or other designs should come into wide-spread use, fuel requirements would be substantially changed in the latter portion of the forecast period.

TABLE 33

Uranium Reserves, West Region, January 1, 1968, Distributed by States

	Tons of ore	Percent U_3O_8	Tons U_3O_8	Percent of total
Arizona	210, 000	0. 21	430	0. 3
Colorado	3, 560, 000	0. 26	9, 390	6. 3
New Mexico	28, 620, 000	0. 24	69, 800	47. 2
North and South Dakota	430, 000	0. 30	1, 280	0. 9
Utah	3, 210, 000	0. 32	10, 300	6. 9
Wyoming	26, 380, 000	0. 20	53, 000	35. 8
Others: California, Oregon, Washington, Nevada, Idaho, Montana, Texas, Alaska	1, 590, 000	0. 23	3, 800	2. 6
Total	64, 000, 000		148, 000	100. 0

Source: U.S. Atomic Energy Commission, Division of Raw Materials, Washington, D.C. 1968.

TABLE 34

Uranium—Estimated Uranium Resources of the United States (Short Tons U_3O_8), January 1, 1968

Price range ($/lb. U_3O_8)	Reasonably assured reserves	Estimated additional resources
10 or less:		
Conventional deposits [1]	190, 000	325, 000
Phosphate byproduct	90, 000	....
Copper leach byproduct	30, 000	25, 000
Total	[2] 310, 000	350, 000
10 to 15:		
Conventional deposits [1]	100, 000	200, 000
Phosphate byproduct	50, 000	....
Total	150, 000	200, 000
Subtotal 15 or less	460, 000	550, 000
15 to 30:		
Conventional deposits [1]	100, 000	140, 000
Phosphate leached zone	[3] 100, 000	[4] 300, 000
Total	200, 000	440, 000
Total 30 or less	660, 000	990, 000

[1] Primarily tabular impregnations in sedimentary rocks; information on deposits in the higher price ranges is limited, and the estimates should be considered preliminary and partial.

[2] Availability through 1980 estimated at 210,000 tons because of limited byproduct capability.

[3] Byproduct.

[4] Primary production.

Source: U.S. Atomic Energy Commission Division of Raw Materials, Washington, D.C. 1968.

TABLE 35

Estimated Fuel Reserves—West Region

Fuel	Date	Amount	Trillion Btu [1]	Percent of— Conventional fuels	All fuels	Source
Natural gas	1966	30,464 billion cu. ft.	32, 700	0. 4	0. 3	Table 17.
Crude petroleum and natural gas liquids.	1966	8,510 million barrels	49, 400	. 5	. 5	Table 23.
Shale oil (25 gal./ton or more yield)	1965	665 billion barrels	3, 857, 000	41. 9	41. 3	([2]).
Coal	1968	263,230 million tons	5, 264, 600	57. 2	56. 3	Table 28.
Subtotal—conventional fuels			9, 203, 700	100. 0	98. 4	
Uranium [3] (U_3O_8)	1968	148,000 tons	88, 500		1. 0	Table 33.
Thorium [3]	1968	100,000	61, 400		. 6	Table 42.
Total—all fuels			9, 353, 600		100. 0	

NOTE.—Possible additional energy with improved technology:

Fuel	*Trillion Btu*	
Uranium	8, 750, 000	1.6 times the conventional fuel energy supply.
Thorium	6, 100, 000	
Total	14, 850, 000	

[1] Conversion factor, Table 45.

[2] U.S. Bureau of Mines—Mineral Facts and Problems—1965.

[3] Assuming 1% fuel burnup in mixture of fissile and fertile Isotopes. It is expected that percent of burnup will increase as new reactors go on stream. Breeder reactors, however, are not likely to have any significant impact on fuel use within the forecast period.

TABLE 36

Natural Gas, Estimated Average Price at Well, 1946–65

[Cents per mcf]

Year	California	Northwest: Montana	Northwest: Wyoming	Rocky Mountain: Arizona	Rocky Mountain: Colorado	Rocky Mountain: New Mexico	Rocky Mountain: Utah	United States
1946	7. 4	4. 6	3. 8		4. 7	1. 4	5. 0	5. 3
1947	10. 2	4. 6	5. 0		7. 9	1. 8	5. 4	6. 0
1948	11. 3	4. 6	5. 9		6. 0	2. 7	6. 0	6. 5
1949	11. 8	5. 6	5. 6		5. 2	2. 9	6. 0	6. 3
1950	11. 9	5. 3	6. 0		3. 9	3. 0	6. 0	6. 5
1951	14. 6	5. 5	7. 5		4. 3	3. 8	6. 6	7. 3
1952	16. 7	6. 1	7. 8		5. 5	4. 6	7. 5	7. 8
1953	19. 7	5. 9	7. 9		5. 8	6. 1	11. 4	9. 2
1954	20. 6	6. 8	8. 4		8. 7	7. 8	14. 1	10. 1
1955	22. 2	6. 1	8. 5		9. 4	8. 6	13. 9	10. 4
1956	22. 5	6. 8	8. 6	14. 0	9. 8	8. 8	14. 1	10. 8
1957	23. 7	7. 2	8. 7		10. 0	9. 4	14. 7	11. 3
1958	23. 3	6. 8	8. 4		10. 5	10. 4	14. 7	11. 8
1959	24. 6	7. 5	8. 1		11. 0	10. 0	14. 2	12. 9
1960	26. 7	7. 1	12. 0		11. 9	10. 7	18. 0	14. 0
1961	28. 3	7. 4	12. 5		11. 6	10. 9	15. 7	15. 1
1962	29. 0	7. 4	14. 6	11. 9	11. 6	11. 5	16. 8	15. 5
1963	29. 3	7. 5	14. 2	12. 1	11. 7	11. 9	18. 2	15. 8
1964	30. 1	7. 8	12. 9	12. 0	11. 9	11. 7	13. 7	15. 4
1965	30. 9	8. 2	13. 5	12. 1	12. 9	11. 8	12. 5	15. 6

Source: U.S. Bureau of Mines, *Minerals Yearbook*, annual; and preprints therefrom.

TABLE 36–A

Average Value of Natural Gas at Wellheads, by States and Regions, 1955–65

[Cents per mcf]

Region and State	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965
Middle Atlantic	29.9	32.1	31.0	28.4	29.2	31.8	29.4	27.2	26.1	27.3	26.9
New York	29.5	28.3	28.4	30.6	30.5	30.9	29.5	28.1	29.5	30.8	30.8
Pennsylvania	29.9	32.2	31.1	28.3	29.2	31.8	29.4	27.2	26.0	27.2	26.7
East North Central	19.0	19.8	21.1	19.2	21.2	21.0	21.8	22.4	24.0	23.2	23.1
Illinois	14.2	15.1	15.5	14.8	13.9	12.5	12.8	14.3	12.9	11.5	11.7
Indiana	12.4	12.1	13.1	15.6	19.0	18.8	20.1	21.1	23.4	23.5	23.6
Michigan	11.5	13.3	18.8	18.6	23.0	21.4	21.1	21.3	27.1	25.3	25.1
Ohio	22.5	24.0	23.7	21.4	23.2	23.5	24.9	25.6	24.2	23.8	23.6
West North Central	12.0	11.5	11.5	11.4	12.0	11.8	12.6	12.6	13.6	12.9	13.4
Kansas	11.1	11.3	11.4	11.4	12.0	11.7	12.5	12.4	13.3	12.5	13.3
Missouri	20.0	16.7	16.7	...	...	25.0	24.7	25.0	27.0	24.3	24.5
Nebraska	20.4	21.0	16.0	15.0	15.9	17.5	16.7	18.2	18.8	15.3	14.6
North Dakota	7.7	8.1	9.5	9.7	9.9	11.4	12.6	13.7	19.1	22.0	16.0
South Atlantic	23.8	23.8	23.9	24.9	26.0	26.2	27.4	27.5	26.6	25.0	23.4
Florida	10.0	8.3	13.0	13.6	14.3	16.2	18.9	20.7	20.0	13.3	12.9
Maryland	20.1	25.3	26.2	26.9	27.0	26.6	27.2	27.0	26.9	26.5	25.2
Virginia	26.8	27.7	26.8	27.0	26.2	27.1	27.1	21.1	23.4	29.8	29.9
W. Virginia	23.5	23.7	23.8	24.8	26.0	26.2	27.4	27.5	26.6	25.0	23.5
East South Central	14.0	13.6	14.2	17.1	18.0	20.5	20.4	20.7	19.7	19.2	19.3
Alabama	6.8	7.9	6.4	9.2	9.7	7.3	7.4	9.8	11.8	11.1	12.7
Kentucky	23.7	23.1	23.8	24.1	23.7	24.4	24.8	24.8	23.9	23.6	23.6
Mississippi	9.6	9.8	10.3	13.9	15.5	18.8	18.6	19.0	18.0	17.3	17.3
Tennessee	12.8	12.9	15.8	16.7	16.7	17.5	18.3	18.5	18.9	19.0	19.0
West South Central	8.7	9.3	10.0	10.9	12.0	13.1	14.3	14.8	15.1	14.7	14.6
Arkansas	5.6	6.0	7.2	8.1	8.7	11.9	13.5	14.9	15.5	15.5	15.6
Louisiana	11.3	11.4	11.2	12.9	15.4	17.1	18.7	19.7	19.8	19.0	18.2
Oklahoma	7.4	8.0	8.3	10.1	10.0	11.9	12.1	12.8	13.0	12.6	13.8
Texas	8.0	8.7	9.7	10.0	10.8	11.3	12.3	12.3	12.5	12.4	12.9
Mountain	8.9	9.3	9.4	10.1	9.9	11.2	11.4	12.3	12.6	11.9	12.1
Arizona	...	14.0	...	...	...	...	...	11.9	12.1	12.0	12.1
Colorado	9.4	9.8	10.0	10.5	11.0	11.9	11.6	11.6	11.7	11.9	12.9
Montana	6.1	6.8	7.2	6.8	7.5	7.1	7.4	7.4	7.5	7.8	8.2
New Mexico	8.6	8.8	9.4	10.4	10.0	10.7	10.9	11.5	11.9	11.7	11.8
Utah	13.9	14.1	14.7	14.7	14.2	18.0	15.7	16.8	18.2	13.7	12.5
Wyoming	8.5	8.6	8.7	8.4	8.1	12.0	12.5	14.6	14.2	12.9	13.5
Pacific	22.2	22.5	23.7	23.3	24.6	26.7	28.3	29.0	29.3	29.9	30.8
Alaska	...	...	...	...	12.0	12.2	20.4	21.4	24.7	27.4	24.8
California	22.2	22.5	23.7	23.3	24.6	26.7	28.3	29.0	29.3	30.1	30.9
United States	10.4	10.8	11.3	11.8	12.9	14.0	15.1	15.5	15.8	15.4	15.6

Source: U.S. Bureau of Mines, *Mineral Yearbook*, Annual; preprints therefrom.

TABLE 37

Natural Gas, Average Price for Industrial Use (Including Electric Generation), at Point of Use, 1946–66

[Cents per mcf]

Year	California	Northwest					Rocky Mountain					United States
		Idaho	Montana	Oregon	Washington	Wyoming	Arizona	Colorado	Nevada	New Mexico	Utah	
1946	13.4	----------	13.7	----------	----------	12.0	20.5	13.7	----------	12.3	[1] 16.2	10.7
1947	18.0	----------	13.6	----------	----------	23.5	20.7	14.5	----------	5.0	[1] 15.5	11.3
1948	21.2	----------	13.6	----------	----------	9.6	21.8	13.9	----------	6.0	[1] 16.2	12.5
1949	19.6	----------	14.7	----------	----------	8.9	20.5	13.6	----------	5.6	[1] 20.7	12.9
1950	18.9	----------	14.2	----------	----------	8.8	20.3	14.6	----------	6.4	[1] 20.7	13.4
1951	21.3	----------	16.0	----------	----------	[2] 14.9	21.2	14.2	----------	6.5	([2])	14.6
1952	23.4	----------	19.2	----------	----------	10.6	22.8	15.4	----------	6.6	26.1	16.2
1953	38.0	----------	19.4	----------	----------	11.8	25.9	15.1	----------	8.0	26.9	18.2
1954	25.2	----------	20.1	----------	----------	11.9	25.5	18.2	----------	9.8	26.9	19.2
1955	26.5	----------	20.2	----------	----------	11.8	27.1	20.5	([4])	11.1	27.5	19.6
1956	28.4	[3] 82.5	20.6	[3] 82.5	79.7	13.6	[4] 24.0	21.0	([4])	12.2	26.9	21.5
1957	30.1	33.3	20.8	[2] 33.9	37.2	12.9	26.1	21.3	38.0	11.2	27.0	22.5
1958	33.8	37.7	21.8	39.0	38.5	12.8	27.0	18.8	59.9	11.8	27.3	23.6
1959	34.9	36.6	22.6	39.2	42.5	13.2	28.4	22.3	60.0	11.4	27.0	25.1
1960	36.8	38.2	23.4	39.4	39.8	14.4	30.4	21.6	61.0	13.9	27.3	27.1
1961	38.0	38.7	22.7	39.9	38.9	15.0	31.7	22.7	62.0	13.5	27.5	26.9
1962	39.3	39.3	21.8	40.8	39.3	13.7	35.4	22.6	62.0	14.0	27.6	28.0
1963	38.3	39.9	22.5	40.3	40.1	13.1	39.8	22.1	62.5	16.8	26.5	28.1
1964	37.5	40.2	26.7	40.4	36.5	15.3	31.9	23.2	44.5	17.0	25.6	28.8
1965	45.3	34.2	27.4	40.2	39.0	16.7	32.5	24.9	45.7	16.3	26.7	29.6
1966 [5]	34.9	37.8	27.1	41.9	37.3	18.2	33.7	23.6	44.3	19.7	27.5	30.1

[1] Includes also Wisconsin except in 1950; N.D., S.D.
[2] Utah included with Wyoming.
[3] Oregon included with Idaho.
[4] Nevada included with Arizona.
[5] Preliminary.
Source: U.S. Bur. of Mines, *Minerals Yearbook*, annual; preprints therefrom; Mineral Industry Survey, Natural Gas, 1966.

TABLE 38

Natural Gas Cost for Electric Utility Generation, Selected States, 1950–1966

[Cents per mcf]

Year	Arizona	California	Montana	Nevada	Oregon	Utah	Wyoming	Colorado	New Mexico	Pacific Coast region [1]	Rocky Mountain subregion [2]	United States
1950	N.A.	N.A.	N.A.	--------	--------	N.A.	N.A.	--------	N.A.	21.3	15.2	11.8
1951	18.3	22.6	31.0	--------	--------	—.8	21.8	11.8	19.5	22.6	15.9	13.6
1952	19.2	25.1	18.8	--------	--------	--------	23.9	12.1	19.8	25.1	16.0	14.7
1953	24.1	26.2	20.8	--------	--------	20.6	17.2	13.2	20.1	26.2	17.8	16.7
1954	24.2	26.3	31.0	--------	--------	20.4	20.8	16.1	19.9	26.3	19.7	18.3
1955	27.0	27.6	31.5	41.5	27.6	20.7	19.1	17.0	19.4	27.6	20.9	18.8
1956	27.1	28.2	24.9	35.1	--------	20.9	20.2	16.8	20.6	28.2	22.1	18.9
1957	27.4	29.4	7.5	35.0	37.0	22.0	18.2	16.7	22.0	29.4	22.1	20.1
1958	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	34.4	23.2	21.9
1959	31.1	34.9	20.0	40.3	38.1	23.0	19.9	18.8	23.8	34.9	25.9	23.6
1960	34.0	35.9	34.0	41.6	38.0	24.5	17.5	19.4	24.7	35.9	27.9	25.2
1961	35.7	37.8	23.6	43.1	38.5	24.4	18.0	18.7	24.9	37.8	29.0	27.0
1962	35.6	37.8	34.0	43.0	38.6	24.8	17.9	19.3	25.4	37.8	29.7	27.2
1963	33.7	36.0	34.0	41.7	38.5	24.7	8.6	18.9	24.6	36.0	28.2	26.1
1964	32.4	34.6	34.0	40.1	47.2	24.7	--------	19.0	24.5	34.6	27.3	26.1
1965	32.3	34.1	34.0	40.8	38.5	24.5	--------	19.1	24.2	34.1	27.0	25.7
1966	32.3	34.0	34.0	40.0	38.5	24.3	--------	19.2	23.3	34.0	26.7	25.8

California, Oregon (none reported for Washington).
[2] Arizona, Colorado, Montana, Nevada, New Mexico, Utah, Wyoming (none reported for Idaho).
N.A. Not available.
Source: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry, 1950–1966*.

TABLE 39

Residual Fuel Oil, Average Prices, Selected Locations, United States, 1946–1966

[Dollars per barrel, Bunker C or equivalent]

Year	Richmond, Calif.	Los Angeles, San Pedro	New Orleans	All gulf ports	Oklahoma No. 6 at refineries	New York Harbor	Unweighted average Los Angeles, Gulf, New York
1946	1. 27	1. 22	1. 23	1. 25	1. 16	1. 76	1. 41
1947	1. 60	1. 55	1. 76	2. 04	2. 01	2. 29	1. 96
1948	2. 16	2. 11	2. 51	2. 87	2. 44	3. 00	2. 66
1949	1. 67	1. 64	1. 57	1. 56	1. 08	1. 90	1. 70
1950	1. 43	1. 41	1. 78	1. 75	1. 64	2. 09	1. 75
1951	1. 75	1. 78	1. 85	1. 83	1. 80	2. 32	1. 98
1952	1. 75	1. 70	1. 75	1. 76	1. 20	2. 31	1. 92
1953	1. 84	1. 79	1. 80	1. 82	1. 21	2. 15	1. 92
1954	1. 85	1. 80	1. 95	1. 93	1. 45	2. 24	1. 99
1955	1. 88	1. 83	2. 11	2. 04	1. 74	2. 48	2. 13
1956	2. 17	2. 18	2. 23	2. 19	2. 14	2. 76	2. 38
1957	2. 83	2. 83	2. 72	2. 85	2. 40	3. 12	2. 93
1958	2. 47	2. 43	2. 31	2. 25	1. 73	2. 60	2. 43
1959	2. 15	2. 10	2. 10	2. 05	1. 97	2. 38	2. 18
1960	2. 17	2. 13	2. 19	2. 20	1. 89	2. 45	2. 26
1961	2. 25	2. 20	2. 30	2. 31	1. 88	2. 52	2. 34
1962	2. 34	2. 29	2. 30	2. 15	1. 90	2. 47	2. 30
1963	2. 27	2. 24	2. 19	2. 18	1. 90	2. 30	2. 24
1964	2. 25	2. 20	2. 19	2. 10	1. 96	2. 30	2. 20
1965	2. 25	2. 20	2. 19	2. 10	2. 08	2. 58	2. 29
1966	2. 25	2. 20	2. 19	2. 10	2. 15	2. 25	2. 18

From Platts Oil Price Handbook, Annual.

TABLE 40

Residual Fuel Oil Costs for Electric Utility Generation, Selected States, 1950–1966

[Dollars per barrel]

Year	Arizona [1]	California	Nevada [1]	Montana	Oregon	Utah	Colorado	Wyoming	New Mexico	Washington	Pacific coast region [2]	Rocky Mountain subregion [3]	United States
1950	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	1.35	2.63	2.00
1951	4.46	1.69	6.24	1.82	2.18	2.08	2.33	4.02	2.20	1.67	1.69	2.35	2.11
1952	3.88	1.76	6.34	1.24	2.07	1.70	2.30	4.23	2.73	2.06	1.82	1.68	2.14
1953	4.24	1.82	6.59	1.00	2.28	1.64	2.35	4.37	4.11	2.07	1.83	1.56	2.05
1954	4.26	1.80	7.03	1.37	2.46	1.51	2.04	4.56	2.70	2.12	1.80	1.63	2.11
1955	4.35	1.78	4.29	4.27	2.27	1.57	2.06	3.78	2.47	2.09	1.78	1.69	2.12
1956	3.96	2.17	3.60	----	2.53	1.67	2.20	----	3.09	----	2.17	1.82	2.42
1957	4.71	2.59	4.69	1.11	3.12	1.65	2.43	3.93	2.42	3.27	2.60	1.72	2.79
1958	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	2.54	1.61	2.47
1959	4.70	2.14	8.13	7.01	2.69	1.51	2.38	3.14	2.58	3.33	2.14	1.54	2.22
1960	2.54	2.07	5.02	7.07	2.92	1.56	2.50	4.31	2.16	----	2.07	1.63	2.17
1961	3.41	2.11	4.35	7.14	2.97	1.60	2.28	4.00	2.28	----	2.11	1.69	2.23
1962	2.64	2.17	4.24	----	2.53	1.51	2.42	4.14	2.25	----	2.17	1.63	2.18
1963	2.30	2.10	4.15	----	2.47	1.60	2.87	3.72	1.62	----	2.10	1.77	2.12
1964	2.38	1.98	4.25	----	----	1.60	2.38	3.72	1.61	----	1.98	1.74	2.08
1965	3.64	2.11	3.72	----	2.52	1.61	2.77	3.49	1.54	----	2.11	1.73	2.10
1966	3.67	2.07	4.12	----	2.45	1.61	2.95	4.12	1.62	2.36	2.07	1.74	2.08

[1] Includes nonresidual oil.
[2] California, Oregon, Washington.
[3] Arizona, Colorado, Montana, Nevada, New Mexico, Utah, Wyoming (none reported for Idaho).
N.A. Not available.

Source: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry*, 1950–1966.

TABLE 41

Coal, Average Price f.o.b. Mines, Selected Western States, 1954–1966

[Dollars per short ton]

Year	Arizona	Colorado	Montana	New Mexico	Utah	Washington	Wyoming	United States
COAL SOLD IN OPEN MARKET								
1954.......	6.23	4.80	N.A.	5.88	N.A.	N.A.	N.A.	4.22
1955.......	6.00	4.82	4.84	6.14	5.04	6.92	3.52	4.26
1956.......	5.11	4.90	5.06	5.80	4.94	7.20	3.43	4.60
1957.......	5.37	5.10	5.62	6.12	5.12	7.60	3.35	4.82
1958.......	5.64	5.18	4.97	6.18	5.05	7.73	3.48	4.58
1959.......	5.92	4.92	4.28	5.42	5.39	7.55	3.65	4.49
1960.......	10.50	5.04	3.79	6.72	5.04	7.51	3.59	4.38
1961.......	N.A.	5.28	3.26	6.07	4.85	7.20	3.27	4.25
1962.......	N.A.	5.04	2.98	3.17	4.71	6.90	3.35	4.19
1963.......	N.A.	4.99	2.82	2.36	4.75	7.21	3.70	4.12
1964.......	N.A.	5.04	2.68	2.40	4.62	8.45	3.66	4.11
1965.......	N.A.	4.67	2.87	2.47	4.57	9.07	3.64	4.13
1966.......	N.A.	4.52	3.07	2.53	4.84	8.77	3.63	4.24
ALL COAL, INCLUDING ESTIMATE FOR COAL NOT SOLD IN OPEN MARKET								
1954.......	6.23	5.54	N.A.	5.91	5.94	7.23	4.08	4.52
1955.......	6.66	5.63	2.00	6.13	6.35	6.99	4.05	4.70
1956.......	6.56	5.66	3.20	5.82	5.28	7.26	3.89	4.82
1957.......	7.02	6.08	4.65	6.05	5.87	7.66	3.76	5.08
1958.......	7.03	6.47	2.82	6.15	5.70	7.80	3.57	4.86
1959.......	8.64	6.39	7.00	5.64	6.16	7.60	3.37	4.77
1960.......	10.50	5.85	N.A.	5.93	6.35	7.54	3.45	4.69
1961.......	N.A.	9.69	N.A.	6.00	7.09	9.38	3.48	6.35
1962.......	N.A.	9.39	N.A.	5.01	6.27	9.26	3.04	6.25
1963.......	N.A.	9.60	N.A.	6.00	5.69	9.30	2.65	6.08
1964.......	N.A.	6.39	N.A.	9.41	9.34	N.A.	2.63	6.24
1965.......	N.A.	6.42	8.17	9.41	8.00	N.A.	2.68	6.21
1966.......	N.A.	6.37	7.31	8.36	7.44	N.A.	2.90	6.43

N.A. Not available.

Source: U.S. Bureau of Mines, *Minerals Yearbook*, 1954–1966, and chapter preprints therefrom.

TABLE 42

Coal Cost for Electric Utility Generation, Western Region, 1948–1966

[Dollars per ton]

Year	Arizona	Colorado	Montana	New Mexico	Oregon [1]	Utah	Washington	Wyoming	Pacific Region [1, 2]	Mountain Region [3]	United States
1948	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	1.04	5.04	6.69
1949	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	1.08	4.89	6.50
1950	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	.70	4.63	6.38
1951		4.72	---	6.65	.70	6.51	---	3.09	.70	4.67	6.42
1952	.19	4.84	---	6.77	.76	6.47	---	2.96	.76	3.71	6.52
1953		4.96	---	7.26	.78	6.27	---	2.94	.78	4.86	6.52
1954		5.00	---	7.56	.82	5.95	---	2.93	.82	4.63	6.25
1955		5.01	---	---	.82	5.29	2.55	2.55	.82	4.34	6.01
1956	.16	5.56	---	---	.85	5.46	---	2.75	.85	4.02	6.29
1957	.20	5.46	---	---	.83	5.29	---	2.84	.83	4.10	6.62
1958	N.A.	4.96	2.89	N.A.	N.A.	N.A.	N.A.	1.71	.57	4.54	6.55
1959		5.35	2.80	---	.62	5.34	---	1.93	.62	4.04	6.28
1960		4.96	2.89	---	2.09	5.38	---	1.71	2.09	3.75	6.26
1961		4.82	2.89	---	2.70	5.38	---	1.73	2.70	3.70	6.22
1962	4.70	5.01	2.92	5.72	---	5.47	---	1.78	3.10	3.87	6.15
1963	3.24	5.00	2.88	3.06	3.84	5.48	---	1.86	3.48	3.49	6.00
1964	2.74	4.99	2.89	2.74	---	5.61	---	2.07	---	3.35	5.88
1965	2.77	5.01	2.90	2.77	6.28	5.62	---	1.87	6.28	3.35	5.83
1966	2.89	4.95	2.66	2.89	4.68	5.67	---	1.73	4.68	3.41	5.85

N.A. Not available.

[1] Oregon data includes equivalent hogged wood from lumber mills.

[2] California, Oregon, and Washington, but based almost entirely on Oregon data.

[3] Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming.

Source: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry*, Annual.

TABLE 43

Delivered Fuel Cost for Electric Utility Generation, Selected States, 1951–1966

[Cents per million BTU]

Year	Arizona				California			Nevada			Oregon [1]		
	Gas	Oil	Coal	Total	Gas	Oil	Total	Gas	Oil	Total	Gas	Oil	Total
1951	16.8	73.6	....	17.3	20.7	26.7	23.7	....	109.0	109.0	....	34.8	14.9
1952	17.6	63.5	....	16.7	23.1	27.8	25.2	....	111.0	111.0	....	32.7	22.4
1953	21.9	70.6	....	22.2	23.9	28.6	26.0	....	112.0	112.0	....	35.6	19.2
1954	21.8	70.6	....	22.0	24.1	28.3	25.1	....	119.5	119.5	....	39.0	13.5
1955	24.6	72.0	....	24.6	25.6	27.9	26.5	38.1	68.4	56.3	25.5	27.8	26.3
1956	24.6	65.6	....	24.1	26.1	34.1	29.7	32.2	55.6	32.7	....	40.1	22.5
1957	25.1	76.9	....	24.6	27.3	40.6	33.0	32.1	67.2	32.2	34.4	48.8	23.0
1958	N.A.	N.A.	....	N.A.	31.8	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
1959	28.9	75.4	....	28.9	32.4	33.0	32.6	37.1	137.0	37.2	35.9	42.0	18.8
1960	31.6	40.5	....	31.7	33.3	32.2	33.0	38.3	85.3	38.4	35.9	45.7	17.4
1961	33.2	53.8	....	33.3	35.0	32.8	34.5	39.8	70.6	40.1	35.9	46.7	20.7
1962	33.2	41.9	22.8	32.3	34.8	33.3	34.5	39.9	71.9	40.3	36.0	39.5	21.2
1963	31.4	36.1	17.4	29.6	33.5	32.6	33.4	38.6	70.9	39.7	35.9	38.7	23.8
1964	30.1	38.5	14.8	27.7	32.2	30.8	37.0	37.3	72.3	38.0	43.9	....	43.9
1965	30.1	57.2	15.1	27.5	31.7	32.6	31.8	37.7	63.5	86.4	35.9	39.1	28.2
1966	30.1	57.6	15.7	27.8	31.6	32.2	31.7	37.3	70.4	35.4	36.0	38.1	25.5

Year	Utah				Colorado				New Mexico			
	Gas	Oil	Coal	Total	Gas	Oil	Coal	Total	Gas	Oil	Coal	Total
1951	....	33.3	26.4	28.1	14.0	36.8	22.0	17.6	18.4	37.3	26.6	18.9
1952	....	26.9	26.0	26.4	14.2	37.3	23.4	17.3	18.5	44.6	28.2	18.9
1953	22.7	26.0	25.2	25.4	15.8	37.6	23.8	18.2	18.8	70.0	29.0	19.2
1954	23.8	23.6	24.0	23.9	19.4	32.4	23.8	20.7	18.6	45.4	30.2	18.7
1955	22.7	24.6	21.3	22.6	20.2	32.7	24.5	21.3	18.3	41.0	....	18.4
1956	22.9	26.0	21.8	23.3	20.1	34.9	25.8	22.2	19.3	51.9	....	19.5
1957	24.2	25.8	21.2	23.7	20.0	39.2	26.8	21.9	20.5	40.2	....	20.6
1958	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
1959	25.4	23.8	21.2	23.0	22.3	37.7	26.2	23.9	22.1	42.8	....	22.1
1960	26.9	24.4	21.6	23.5	22.9	41.3	24.6	23.5	23.5	34.8	....	23.6
1961	26.6	25.1	21.4	23.6	21.7	36.2	22.7	22.3	23.6	35.7	....	23.8
1962	26.6	....	21.8	23.3	22.2	....	23.5	23.0	24.1	35.2	....	24.2
1963	26.6	24.9	22.1	23.9	22.1	45.6	23.4	27.9	23.4	25.3	16.4	21.3
1964	26.5	24.9	22.3	24.0	21.9	37.7	23.4	27.8	23.4	25.2	14.8	19.3
1965	26.4	25.0	22.3	24.2	22.0	44.9	23.5	22.9	23.2	24.4	15.1	19.0
1966	26.2	24.9	22.6	24.3	22.1	47.7	23.2	22.9	22.5	25.7	15.7	19.4

Year	Pacific Coast Region [2]			Rocky Mountain Region [3]				United States			
	Gas	Oil	Total	Gas	Oil	Coal	Total	Gas	Oil	Coal	Total
1951	20.7	26.7	23.4	16.4	38.0	24.2	18.8	13.9	33.4	26.8	24.8
1952	23.1	28.6	25.3	16.5	26.6	24.7	18.8	15.2	33.9	27.2	25.0
1953	23.9	28.7	25.9	18.5	24.7	24.5	20.3	16.7	32.5	27.2	25.2
1954	24.1	28.3	24.9	20.5	25.8	23.9	21.2	17.9	33.4	25.9	24.4
1955	25.6	27.9	26.3	21.5	26.5	22.9	21.6	18.7	33.5	25.0	24.3
1956	26.1	34.1	29.6	22.3	28.4	23.3	22.4	18.9	38.5	26.2	25.4
1957	27.3	40.6	32.6	22.3	27.1	24.0	22.4	20.2	44.2	27.6	27.1
1958	31.8	39.9	34.2	23.2	25.1	N.A	23.1	21.6	39.4	27.2	26.8
1959	32.4	33.1	32.5	25.7	24.2	23.2	24.5	23.2	35.1	26.1	26.1
1960	33.3	32.3	32.9	27.9	25.6	23.1	25.7	24.4	34.4	26.0	26.2
1961	35.0	32.8	34.4	28.7	26.5	22.0	25.9	26.2	35.2	25.9	26.7
1962	34.8	33.3	34.5	27.5	....	22.1	25.8	26.3	34.5	25.6	26.4
1963	33.5	32.6	33.4	29.3	26.2	22.7	26.1	25.4	33.3	25.0	25.7
1964	32.2	30.8	32.0	26.2	25.7	22.8	25.2	25.3	32.7	24.5	25.3
1965	31.7	32.6	31.8	26.1	25.5	22.7	25.1	24.9	33.3	24.4	25.2
1966	31.6	32.2	31.7	26.1	26.3	22.9	25.2	25.0	32.9	24.6	25.4

N.A. Not available.

[1] Includes cob wood fuel.

[2] California, Oregon, Washington.

[3] Arizona, Colorado, Nevada, New Mexico, Utah.

Data Source: Tables 35, 37 and 39 and Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry.*

TABLE 44

Cost of Transporting Energy, by Form of Energy and Means of Transportation

Form of energy	Means of transportation	Transportation cost per 100 miles [a]: ¢ Million Btu	Transportation cost per 100 miles [a]: Mills/Kwh [b]	Source
Nuclear fuel	Railroad	Under 0.03	Under 0.003	c
Oil	Tanker ship	0.1 to 0.5	0.01 to 0.05	d, e, q
	Pipeline	0.4 to 1.6	0.04 to 0.16	e, f, n, q
	Barge (average)	0.5	0.05	q
	Railroad tank car (average)	4.3	0.43	q
	Truck (average)	7.4	0.74	q
Natural gas (gas)	Pipeline	1.1 to 2.4	0.11 to 0.24	e, n, p
Natural gas (liquefied)	Tanker	0.5 to 0.9	0.05 to 0.09	o
	Barge	0.6	0.06	o
	Railroad	2.7	0.27	o
Coal	Slurry pipeline	1.0 to 2.0	0.1 to 0.2	e
		1.5 to 5.0	0.15 to 0.5	g, h, k, s
	Railroad: Intergal train	0.7 to 2.0	0.07 to 0.2	i, k, t
	Shuttle train	1.5 to 3.5	0.15 to 0.35	j
		1.8 to 3.6	0.18 to 0.36	k, n, s, u
	At filed tariffs	3.0 to 7.6	0.3 to 0.76	e
		3.6 to 8.3	0.36 to 0.83	k, l
	Western States 1964 average	3.6	0.36	r
Electricity	High voltage transmission line [1]			
At 10,000 Btu/Kwh	700 KV AC	3.0 to 3.6	0.3 to 0.36	n, s, v
	500 KV AC	3.6 to 4.8	0.36 to 0.48	h, k, n, s, v
	345 KV AC	4.8 to 6.6	0.48 to 0.66	h, k, n, s, v
	200 KV AC	6.6 to 9.0	0.66 to 0.90	h, k, n, s, v
	Unspecified voltage	7.8 to 30.0	0.8 to 3.0	m

[1] These figures reflect point to point transmission and are probably on the high side, particularly if transmission is integrated into a transmission network with exchange by displacement possible. The subcommittee accepted the estimates without research as it is informed that the Transmission and Interconnection Special Technical Committee is investigating this matter in detail.

[a] Part of range of costs reflects variation of cost with distance. In many cases somewhat lower costs than those shown might be anticipated for distances over 800 miles.

[b] At heat rate of 10,000 Btu/Kwh.

[c] Computed from data in source e, pages 83, 174–175.

[d] The International Tanker Nominal Freight Scale Association Limited Rates (INTA-SCALE or INTA) London. Both INTA and INTA-50% rates used.

[e] U.S. Senate, Committee on Interior and Insular Affair, 87th Congress, 2d Session, *Report of the National Fuels and Energy Study Group*, Sept. 21, 1962, p. 168.

[f] Interstate Commerce Commission, Bureau of Accounts, *Transport Statistics in the United States*, for the Year ended Dec. 31, 1966, part 6, Oil Pipelines.

[g] Walker, G. H., and E. J. Wasp, "Experience and Prospects in Economic Transportation on Coal in Pipelines," Sixth Annual World Power Conf., Melbourne, Oct. 20–27, 1962. Cited by Southern California Edison Company.

[h] U.S. Department of the Interior, *Report to the Panel on Civilian Technology on Coal Slurry Pipelines*, May 1, 1962.

[i] Kauffeld, T. J., "Use of Integral Trains to Produce Competitive Bulk Transportation Costs." Cited by Southern California Edison Company.

[j] Thomas, J. B., Texas Electric Service Company, Letter to T. J. Galligan, Boston Edison Company, Nov. 21, 1962; p. 2.

[k] Southern California Edison Company.

[l] Western railroads.

[m] Computed from data in source e, page 168.

[n] "The Changing Scene in Mine-to-Market Coal Haulage." Survey by Coal Age of major coal-carrying railroads and representatives of other types of transportation companies—water, pipeline and EHV—December, 1962. Cited by Southern California Edison Company.

[o] "LNG on the Move," Robert E. Petsinger, Gas, Dec. 1967, Jan. 1968, Feb. 1968. Cited by Southern California Edison Company.

p Federal Power Commission Docket CP63-223 Exhibit 24; Gulf Pacific Case. Cited by Southern California Edison Company.

q "9th Annual Study of Pipeline Installation and Equipment Costs," John P. O'Donnell. The Oil and Gas Journal, July 4, 1966. Cited by Southern California Edison Company.

r Interstate Commerce Commission, Bureau of Economics, *Car Load Waybill Statistics, 1964*, State-tc-State Distribution Traffic and Revenue, August 1967.

s "Potential Market for Far Western Coal and Lignite." Two volume report to the United States Department of the Interior, Office of Coal Research. Robert T. Nathan Associates, Inc. Cited by Southern California Edison Company.

t "ICC Streamlines at the Top" (Rent-a-train concept) Business Week, October 14, 1967—Transportation. Cited by Southern California Edison Company.

u "The unit train: approaches to inherent problems" Harold F. Egan. Consumers Power Company. Handling and Shipping, February 1966. Cited by Southern California Edison Company.

v "Transmission Above 700 KV Hits Economic Roadblock," J. K. Dillard, Electric Light and Power, February 1965. Cited by Southern California Edison Company.

TABLE 45

Energy Conversion Factors

Type of fuel or energy	Unit	Equivalent Btu [1]	Source
Electricity:			
At 100% efficient conversion	kwh	3, 413	([2]).
At actual conversion efficiency	kwh	Heat rate (variable)	Compare table 6.
Natural gas	Cubic foot	1, 075	West Coast experience.
Residual fuel	Barrel [3]	6, 400, 000	West Coast experience.
Low sulfur fuel oil	Barrel [3]	6, 000, 000	West Coast experience.
All petroleum products, average	Barrel [3]	5, 800, 000	([4]).
Crude petroleum	Barrel [3]	5, 800, 000	U.S. Bureau of Mines.[5]
Shale oil	Barrel [3]	5, 800, 000	([4]).
Natural gas liquids, including natural gasoline	Barrel [3]	4, 400, 000	U.S. Bureau of Mines.[6]
Liquified petroleum gases	Barrel [3]	4, 011, 000	U.S. Bureau of Mines.[7]
	Gallon	95, 500	U.S. Bureau of Mines.[7]
Coal	Short ton [8]	20, 000, 000	Western States experience (average of bituminous and sub-bituminous).
Fuel wood	Cubic foot	151, 560	
	Cord (128 cu. ft.)	19, 400, 000	([9]).
Nuclear:			
U-235	1 gram	78, 000, 000 (.95 mwdt)	([10]).
U-233	1 gram	79, 500, 000 (.97 mwdt)	
Slightly enriched, light water reactor fuel (mixture of fissile and fertile isotopes) —1% burn-up.	Short ton [8]	598 Billion (7,300 mwdt)	([11]).

1 Conversion factors deviating herefrom sometimes may be used where heat content varies.

2 American Society of Mechanical Engineer, "Steam Tables," 1967 ed., Page 289.

3 42 gallons.

4 Assumed equal to factor for crude petroleum.

5 Mineral Industry Surveys, "Crude Petroleum and Petroleum Products," Dec. 1966, p. 25.

6 Weighted average of figures for natural gasoline and for other natural gas liquids as reported in Schurr and Netschert, *op. cit.*, p. 736.

7 Mineral Industry Surveys, "Crude Petroleum and Petroleum Products, 1961" (Final Summary), p. 29.

8 2,000 pounds.

9 S. H. Schurr and B. C. Netschert, *Energy in the American Economy, 1850–1975*, 1960, p. 33.

10 S. Glasstone and A. Sesonske, *Nuclear Reactor Engineering*, D. Van Nostrand Co., Inc. 1967.

11 General Electric Co., "Pocket Planner," *Technical Data* (1968).

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APPENDIX 3

FUTURE GENERATION PATTERNS FOR THE WEST REGION

Prepared by Task Force on Generation (Subcommittee on Generation)

Introduction

The Task Force on Generation was organized under the West Regional Advisory Committee (WRAC) of the FPC to report on anticipated patterns of generation for target years 1970, 1980, and 1990. The FPC will use this information to update its 1964 National Power Survey.

The following report presents a possible pattern of generation additions within the West Region and is based upon the composite thinking of representatives from the power systems that are responsible for supplying the requirements of the region.

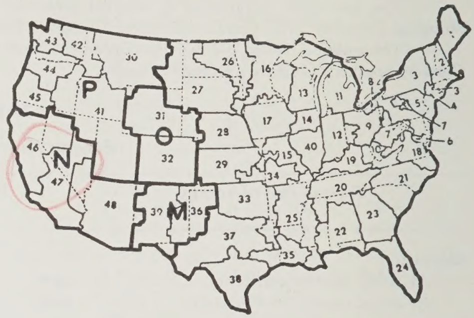
Commitments for new generating facilities are definite for the short term. Therefore, the Task Force selected 1970 as the "benchmark" for making long-range projections. Projections beyond 1970 do not in any way represent commitments of the utilities to any specific program; they are this Task Force's estimate of future generation patterns based on the current outlook.

The Task Force divided the region into four study areas for which generation patterns were developed to meet projected loads for the three target years. Generation patterns are tabulated in Section V and also are symbolized on maps in the appendices.

General Discussion of West Region

The map shows the West Region—the western third of the United States. Note the four study areas: M, N, O, and P. The numbered FPC Power Supply Areas are indicated within each study area.

The West Region is characterized by load centers which are separated both by considerable distances and natural geographic boundaries. Its four study areas generally represent a grouping of utilities that are closely associated because of common transmission grid systems, similar types of generation, common watersheds, and other reasons. However, some of the study areas have within their own boundaries distinctly different characteristics with respect to the availability of water for hydro generation and fossil-fuel supplies for thermal plants.



Following is a brief description of the four study areas:

Area M covers most of New Mexico, the northwest portion of Texas, and the Panhandle of Oklahoma. It does not have large volumes of stream water; therefore, most of the electric generation is from thermal plants. Its major cities are Albuquerque, New Mexico and El Paso, Lubbock, and Amarillo, Texas. Approximately 60 percent of its electric load is in the northwest portion of Texas where there is extensive activity in gas and oil production and agriculture.

Over the 1970 to 1990 period, four types of generation—namely nuclear, gas and oil-fired thermal, coal-fired thermal, and gas turbines—will be installed in the varied regions comprising this area. The gas and oil fossil-fuel energy for large-scale thermal plants will be supplied from the San Juan Basin of Northwestern New Mexico and the Hugoton, Permian, and Delaware Basins of Northwest Texas. These basins have extensive fossil reserves, and will continue to be focal points for thermal generation.

Area N includes most of California and Nevada, all of Arizona, and a small part of New Mexico. Its climate ranges from abundant rainfall in Northern California to semi-arid in the Southwest. Its electric power systems include some with approximately equal hydro and thermal generation and others with all thermal generation. Roughly 85 percent of its electric load lies within California. The major Cal-

ifornia load centers are around San Francisco Bay, Sacramento, Los Angeles, and San Diego. Other large load centers are Reno and Las Vegas, Nevada, and Phoenix and Tucson, Arizona.

Over the 1970 to 1990 period, every significant type of generation—including nuclear; gas, oil, and coal-fired thermal; geothermal; conventional hydro; hydro pumped storage; and gas turbines—will be installed to meet the diverse requirements of the regions comprising this area. Northern and Central California now have a large amount of low-capacity-factor hydro generation. Although more hydroelectric power is scheduled to be developed for peaking purposes, most of the future capacity expansion for Northern and Central California will be in large scale nuclear units. Utilities of the Southwest are planning more coal-fired and nuclear thermal units to fill out the base portion of their loads. They plan to add gas turbines and hydro pumped storage units for peaking and reserve purposes.

Area O includes most of Wyoming, all of Colorado, and the western portion of Nebraska. The Denver load center accounts for almost half of the load. Nearly three-quarters of the generation capability is in thermal plants concentrated at Denver and Hayden, Colorado and at Glenrock, Wyoming near Casper. The hydro generation is concentrated on the North Platte River near Casper, Wyoming and on the South Platte Drainage near Denver. An abundance of low-cost coal is available in Wyoming and Eastern Colorado, and coal-fired thermal plants are expected to provide most of the future generation.

Area P includes quite diverse climatic characteristics, from the heavy rainfall along the Pacific slopes to the dry areas of Southern Utah. The Oregon, Idaho and Washington section of Area P is now dominated by hydro generation. The largest load centers are west of the Cascade Range in the Puget Sound area of Washington and around Portland, Oregon. Other load centers include Spokane, Washington; Boise and Pocatello, Idaho; Salt Lake City, Utah; and Butte, Montana. Because the hydro installations have limited energy available in critical periods, basic planning for new resources is to meet energy requirements. Historically, a surplus of capacity has existed to meet load requirements, and the best utilization of stream flow to fit the load pattern has been and still is the subject of continuous study. Conservation of hydro electric energy has been aided by storage reservoirs and utilization of the diversity of run-off between coastal streams draining the west slope of the Cascades and the Columbia River Basin. Better utilization has been achieved through exchange of energy between utilities and by coordinated operation of storage reservoirs to reduce spill and increase available head. In the future, there may be opportunities to arrange beneficial exchanges of energy and to coordinate storage with Canada.

Utilities of the western part of Area P are planning extensive nuclear installation, while those in the eastern portion of Area P expect to use large coal deposits as the primary source of fuel for new generation. Development of nuclear plants in the eastern portion of Area P will depend upon nuclear power's future comparative economics.

I. Load Projections

Study areas M, N, O, and P, are made up of FPC Power Supply Areas as follows:

Area:	*Power supply areas*
M	36, 39.
N	46, 47, 48.
O	31, 32.
P—East	30, 41.
P—West	42, 43, 44, 45.

Appendix 1 contains load estimates supplied by the San Francisco Regional Office of the Federal Power Commission for each of the FPC Power Supply Areas within the West Region. Although the FPC load projections did not coincide with the utilities' estimates, they were used for all study areas except Area M. Revised load forecasts for Area M were submitted by the utilities from that study area.

The estimates of peak demands for 1970, 1980, and 1990 have been considered as target year load levels. Although the projected loads will not necessarily occur in the specific years assigned, they were used as reference levels for projected generation development. With this qualification, summary tabulations and maps were prepared giving a pattern of possible generation installations to supply the demands for the designated years of 1970, 1980, and 1990. Energy requirements which could be expected to accompany the peak demands were taken into consideration in selecting the composition of generation sources to supply the requirements.

II. Sources of Supply

A. Possible Sources of Future Generation

The usefulness of hydroelectric generation for peaking purposes and for rapid recovery from system disturbances will continue to be an important factor in overall generation planning. Hydro plants therefore will continue to be installed wherever adequate sites exist or where provisions for additional units are available.

As the West Coast adds more and more large thermal plants, the same factors which have justified pumped storage plants in the eastern states may make pumped storage more attractive in the West.

Gas turbine peaking units are expected to be located near load centers at sites where gas and oil-fired plants are presently located. Gas turbines will generally be used for start-up and reserve purposes resulting in very few hours of annual operation. However, they are capable of operating for long periods of time during emergencies.

Nuclear capacity is characterized by its high capital cost, but relatively low incremental fuel cost indicating its use for high load factor operation. Generally, nuclear unit sizes are expected to be among the largest thermal unit sizes because of economies of scale.

Summary tabulations of estimated loads and resources for each area within the region are included as Tables 2, 4, 6, 8, and 10 in Section V. Projections are presented for each of the years 1970, 1980, and 1990. Sources of power to meet loads in the next several years are generally already committed, so data for the year 1970 can be considered an "actual status" summary and also the "bench-mark" for estimated additions in subsequent years.

Maps of the West Region are attached to this report to show the generation patterns and general locations of resources for the years 1970, 1980, and 1990. In many cases several generating plants were combined into a generalized location for purposes of illustration. For this reason, the size of symbols should be considered only as a guide to the amount of that particular type of generation which exists or is estimated to be developed in that portion of the region.

The load shape and reserve requirements for each study area were considered in selecting the proper mix of base load and peaking resources. Future economic considerations will determine the specific types of peaking and base load generation that will be installed.

Area M's generating resources in 1970 will be 84 percent gas and oil-fired thermal, 9.4 percent imported coal-fired thermal from Area N, 3.3 percent hydroelectric, and 3.3 percent gas turbine. By 1980, coal-fired thermal generation will increase to 15.5 percent and gas-fired thermal will drop to 80 percent. By 1990, nuclear generation will supply 9 percent of the generation, gas and oil will remain at 80 percent, and coal will decrease to approximately 9 percent due to limited cooling water supply in the coal area. Because there are extensive gas and oil reserves in PSA–36, gas and oil-fired thermal generation will continue to dominate the generation picture in Area M.

In Area N the 1970 generating resources will be about 25 percent hydroelectric and 60 percent gas and oil-fired thermal. The remainder will be comprised primarily of coal-fired thermal. By 1990, the proportions of hydro and gas and oil-fired thermal will decline respectively to 13 and 23 percent of total resources. This change in the resource pattern will result from the increased use of nuclear capacity for base load generation. Nuclear capacity will change from a bare 1 percent in 1970 to nearly 50 percent of the resources in 1990.

Area O has low-cost coal available in Colorado and Wyoming. Its resource additions through 1980 will be in coal-fired thermal plants except for some minor hydro peaking additions and one nuclear unit. This trend is expected to continue through 1990 for Wyoming. In Colorado, however, nuclear installations may become increasingly competitive with coal because the large concentration of load in the Denver area will allow large units in the 1,000-mw class to be installed with a minimum of transmission.

In the western portion of Area P, assuring an adequate energy supply continues to control the type of generating resource for future installation. Because the remaining undeveloped sources of hydro energy are few, and because only one substantial fossil-fuel-fired thermal plant (Centralia, Washington) appears practicable at this time, virtually all new energy supply is expected to come from nuclear power plants. Additional peaking capacity through 1990 will probably be provided from installation of additional machines at existing hydro projects, although some pumped storage can be expected.

The eastern portion of Area P as of 1970 will have approximately 73 percent hydro and 27 percent thermal capacity. With few economical hydro sites available for development, thermal plants (largely fossil fueled) are expected to be used to provide for load growth in the area. Hydro plants now in the area will be utilized more and more for peaking duty. By 1980 thermal plants are expected to account for 56 percent of the total capacity, and by 1990, this percentage is expected to be 73 percent.

B. Possible Sources of Purchased Power

Present and possible future interchanges within the West Region were considered in the preparation of the resource tabulations. However, the amount of such interchange was considered to be within the rather broad framework of existing contractual relationships recognizing that the economics of specific future proposals could dictate other contracts and the substitution of interchange power for construction of resources within any one area.

With the continued development of the coal resources in Area N, Area M will interchange power and participate in jointly owned generating plants in Area N. Purchases from the areas to the east and south do not show great promise. Although there is not presently an interchange of power between PSA–39 and PSA–36, such interchange may be advantageous in the future if gas fuel costs remain at a low level in PSA–36.

Surplus energy and firm capacity from Area P will be available for a limited time and will be marketed in Area N over EHV interconnections between these areas. Exchange peaking power (capacity and energy delivered at one time and repaid with a greater amount of energy at another time) also will be available from Area P and marketed in Area N. There will be other occasions when surplus energy from Area N will be purchased by or exchanged with Area P.

Potential imports from British Columbia were not included in developing the 1980 and 1990 resource projections for PSA–42, 43, 44, and 45. Although there is substantial undeveloped hydro potential in British Columbia, definite plans for development of all of this potential are not available. The development of about 7 million kilowatts on the Peace and Columbia Rivers is being planned to meet British Columbia's normal load growth through about the mid-1980's. The British Columbia Energy Board reported in 1961 that the power developments on the Peace and Columbia Rivers would cost about 2 mills per kilowatthour at site and 4 mills per kilowatthour at load centers or delivered to the U.S.–Canadian border. Other costs and transmission losses would have to be added if imports were made into the United States.

No interchange was included for Area O in the resource program; however, joint development of resources with systems outside Area O may result in an interchange of firm power in the future.

C. Factors Affecting Selection of Most Promising Sites

Sites for future thermal units must provide the usual necessary features of cooling water supplies, transmission corridors, and suitable geologic conditions. However, to assure public acceptance, increased attention must be paid to environmental considerations, such as esthetics, thermal effects, and air quality control. The location of nuclear plants must also satisfy the special siting requirements of the Atomic Energy Commission. Locating thermal plants near load centers will continue to be desirable in order to minimize the amount of transmission for moving the power to load. On the other hand, it is sometimes necessary to locate the plant in remote areas to avoid adding combustion products to metropolitan environment or to conform to AEC siting requirements. These siting criteria and the application of corollary restraints severely limit the number of sites that can be developed. Difficulty of siting thermal units will have an important impact upon the economy of future generation.

Because the safety of nuclear generation is being clearly demonstrated, most utilities believe the AEC will modify the siting requirements to allow construction of nuclear units closer to metropolitan areas, thus reducing the siting problem for nuclear units.

The best hydro sites throughout the West Region have already been developed. With few exceptions, the remaining sites are economically marginal or not economic at all for single purpose power projects. Nevertheless, there will be an appreciable amount of new hydro developed incidental to irrigation and flood control projects. Additional machines will be installed at some existing hydro plants as the need

for peaking power increases. Also, the installation of pumped storage facilities at both existing and future new sites may become attractive in areas of the West Region which do not already have large amounts of peaking power to absorb.

D. Discussion of Suitability of Generating Sources in Meeting Projected Loads, Including Probable Retirements

In the West Region the development of mine-mouth, coal-fired generation will be limited by the availability of cooling water and can be expected to taper off by 1990. Nuclear power is expected to provide the majority of new thermal generation for the West Region as a whole for the 1970–1990 period. In the Northwest, the transition from basically an all-hydro energy supply to a thermal energy base with hydro peaking is already under way. In California, nearly all the base load generation projected for installation after 1972 is nuclear.

Commercial breeder reactors with their more efficient use of nuclear fuel will undoubtedly become important before 1990. Because the timing of breeder development is presently indefinite, the tabulations do not distinguish between the types of nuclear reactors.

Unique sources of generation such as geothermal power and multi-purpose projects combining waste incineration or desalination with electrical generation are being considered in planned resource additions.

Whenever the economics of large-scale nuclear units and mine-mouth, coal-fired plants dictate their installation, there will be a related reduction in the capacity factor of existing gas and oil-fired generation. The reason for such a reduction is that the incremental energy cost from the large-scale coal and nuclear units will generally be much less than from the older gas and oil units. Conventional gas and oil-fired thermal installations will continue to provide a competitive source of generation in certain portions of the West Region where supplies of these fuels are abundant.

Peaking generation additions will include conventional hydro, pumped storage, combined conventional and pumped storage hydro, and gas turbines where these types of generation are economically competitive and when the load and resource requirements justify their development. Peaking requirements of the Northwest and Northern California generally will be provided by already existing and planned conventional hydro capacity and by further additions of conventional hydro developed in connection with multipurpose water development projects. The Southwest will depend to a greater extent on gas turbines and pumped storage. A major pumped storage project in this area will be located on the California aqueduct near Los Angeles, and will reach an ultimate capacity of 1,200-mw in the mid-1980's. Hydro pumped storage will become more attractive as the proportion of low cost coal and nuclear capacity increases.

Retirements of older generating resources will be almost entirely of conventional gas and oil-fired units. Most hydro units will probably be maintained or reconstructed to keep them in operation. As a result of the rapid growth in size of electric systems, units being retired will represent only a relatively small part of such systems.

III. Generating Reserve Requirements Including Effects of Unit Sizes

In estimating the pattern of future generation, additional capacity above projected load demands was included to provide reserves considered necessary for a reliable power supply. Adverse hydro conditions were assumed in planning generation resources. Each area included an amount of reserve for contingencies which it deemed prudent for its own particular types of generation, extent of resource pooling and other considerations. It was not considered necessary or desirable to establish a uniform reserve criteria to be used by all areas in estimating their future generation requirements.

In some areas reserve requirements expressed as a percent of peak demand are estimated to decrease over the 1970 to 1990 period. Other things being equal, this should be expected as systems get larger. Pooling of resources with adequate interconnections between utilities permits such reductions if unit sizes do not increase. If unit sizes are increased to obtain the economies of scale, then reserves must also increase and may actually increase the percent that reserves represent of total generating resources. Present experience with the large new generating units indicates a relatively high outage rate. As additional operating experience is obtained, an improvement in the reliability of these new generating units may justify a reduction in the amount of ca-

pacity held in reserve. A reduction in reserves must not be equated automatically to good or economic planning because an expansion pattern accompanied by an actual increase in reserves may be the most economic.

First-of-a-kind units will continue to require more test time prior to commercial operation and substantially more reserve capacity because of the lengthy licensing process and unpredictable construction delays. Shakedown of the more complex generating units requires temporarily-increased amounts of reserve capacity until a mature, more reliable performance status is achieved.

Reserve requirements will change with the selection of unit sizes, experience with forced outage rates, number and strength of interconnections, and pooling arrangements.

IV. Coordination of Bulk Power Supply Within and Between Regions

The subject of coordination was generously dealt with in the December 20, 1966 report of the Subcommittee on Coordinated Planning and Development. Existing organizations were well described therein and the report's indication of the trend toward coordination of planning has since been verified in the formation of the Western Systems Coordinating Council (WSCC), which includes some 40 organizations representing virtually all the major utilities in the 13 Western States.

Coordination between utilities, both public and private, has increased significantly over the last few years, and further substantial progress along these lines is anticipated.

Benefits have already been obtained from these coordination efforts and further benefits will accrue in the form of jointly owned large generating units. Projects such as Four Corners, Mohave, and Centralia are excellent examples of joint ownership of large generating units.

Coordination of bulk power supply is a contributing factor to larger economic unit sizes, expected to range up to 1,200 megawatts in the 1970's. Both the utilities and the manufacturers indicate that an assimilation period is prudent before stepping up to larger sizes. In the 1980's, unit sizes may range between 1,500 and 2,000 megawatts; however, the so-called "economy of scale" does have a limit at some point. Future generation patterns envision strong EHV transmission grids within and between the utilities. Coordinated planning will open opportunities for increased reliability, economic benefits through contracts for economy energy interchange, reserve pooling, overhaul schedule optimizing, and coordination of spinning reserve.

V. Generating Capacity Patterns for 1970, 1980, and 1990

Resources tabulations for the base year 1970 and target years 1980 and 1990 are included in this section of the report. Base year resource tabulations include all resources expected to be in commercial operation by 1970. These tabulations describe for each plant or project the general location, the type(s) of unit(s), the capacity, and for thermal plants, the cooling method and source of cooling water. Resources tabulations for 1980 and 1990 describe only the changes in, or additions to base year resources. The location of future plants has been left quite general because the objective of this report is to establish patterns of generation. Also it is impossible at this time to designate specific future sites. Sales and purchases within the grouped power supply areas have been netted out.

Loads and resources summary tables which illustrate the generation capacity patterns show estimated peak loads, resources (classified by type), scheduled overhaul at the time of the peak load, and the reserve margin. Tabulations and summaries are as follows:

Area	Resources Tabulations Table	Loads and Resources Summary Table
M	1	2
N	3	4
O	5	6
P—East	7	8
P—West	9	10

The resources tabulations and loads and resources summary tables reflect an estimated pattern of generation expansion based on current technological developments and foreseeable competition between the various known types of resources.

TABLE 1–1

Generation Resources—PSA 36 as of 1970 (Base Year)

Project name	Location		Unit No.	Type	Capability—mw		Thermal units	
	City	State			Units	Project	Source of water supply	Cooling method
Southwestern Public Service Company:								
Carlsbad	Carlsbad	New Mexico	1, 2, 3, 4	GAOT	48	48	Pecos River	OT
CZ	Pampa	Texas	1	GST	12	12		CT
Cunningham	Hobbs	New Mexico	1, 2	GAOT	275	275	Wells	CT
Denver City	Denver City	Texas	1, 2, 3, 4	GAOT	87	87	Wells	CT
East Plant	Amarillo	Texas	1, 2, 3, 4, 5	GAOT	74	74	Wells	CT
Guymon	Guymon	Oklahoma	1	GST	15	15		CT
Moore County	Sunray	Texas	2, 3	GAOT	69	69		
Nichols	Amarillo	Texas	1, 2, 3	GAOT	412	412	Wells	CT
Plant X	Earth	Texas	1, 2, 3, 4	GAOT	461	461	Wells	CT
Plant 66	Borger	Texas	1	GST	30	30		CT
Riverview	Borger	Texas	2, 3, 4, 5	GAOT	62	62	Wells	CT
Roswell	Roswell	New Mexico	3, 5, 6	GAOT	27		Wells	CT
			7	GST	10	37		CT
Tuco	Abernathy	Texas	2, 3, 4	GAOT	38	38	Wells	CT
Not located		Texas and New Mexico.		GST	30	30		CT
Total Southwestern Public Service Company.						1,651		
Other:								
New Mexico Electric Service Company:								
Maddox	Hobbs	New Mexico	1	GAOT	115	115	Wells	CT
Various municipals:								
Various				Various	203	203		
Total other						318		
Total area 36						1,969		

TABLE 1–2

Generation Resources—PSA 36 As of 1980 (Additions and Deductions Following 1970)

Project name	Location: City	Location: State	Number	Type	Capability—mw: Units	Capability—mw: Project	Thermal units: Source of water supply	Thermal units: Cooling method
Southwestern Public Service Company:								
Denver City	Denver City	Texas	1	GAOT	(8)	79	Wells	CT
East Plant	Amarillo	Texas	1, 2, 3	GAOT	(23)	51	Wells	CT
Jones	South Area	Texas	1	GAOT	234		Wells	CT
			2	GAOT	350	584	Wells	CT
Nichols	Amarillo	Texas	3	GAOT	34		Wells	CT
			4	GAOT	234		Wells	CT
			5	GAOT	350	1,030		
Riverview	Borger	Texas	2, 3, 4	GAOT	(32)		Wells	CT
			6	GAT	170	200	Wells	CT
Tuco	Abernathy	Texas	2	GAOT	(7)	31	Wells	CT
Not located		Texas and New Mexico.		GST	30	30		CT
Total Southwestern Public Service Company.					1,332			
Other:								
New Mexico Electric Service Company:								
Maddox	Hobbs	New Mexico	2, 3	GAOT	230	345	Wells	CT
Various municipals and co-ops.:								
Various				Various	181	384		
Total other					411			
Net generation additions					1,743			
Purchases by PSA 36 from PSA 39.					100	100		
Total area 36					1,843			

TABLE 1–3

Generation Resources—PSA 36 As of 1990 (Additions and Deductions Following 1980)

Project name	Location		Unit No.	Type	Capability—mw		Thermal units	
	City	State			Units	Project	Source of water supply	Cooling method
Southwestern Public Service Company:								
Carlsbad	Carlsbad	New Mexico	2, 3	GAOT	(26)	22	Pecos River	OT
Denver City	Denver City	Texas	2, 3	GAOT	(31)	48	Wells	CT
East Plant	Amarillo	Texas	4	GAOT	(12)	39	Wells	CT
Riverview	Borger	Texas	5	GAOT	(30)	170	Wells	CT
Roswell	Roswell	New Mexico	5	GAOT	(6)	31	Wells	CT
Moore County	Sunray	Texas	4	GAOT	234	303	Wells	CT
Thermal A	Amarillo	Texas	1	GOAT [1]	500		Wells	CT
			2	GAOT [1]	500	1,000		
Thermal B		New Mexico		GAT	170	170	Wells	CT
Jones	South Area	Texas	3	GAOT	500	1,084	Wells	CT
Plant X	Earth	Texas	5	GAOT	500	961	Wells	CT
Thermal C		Texas		GAT	170	170	Wells	CT
Tuco	Abernathy	Texas	3, 4	GAOT	(31)	0	Wells	CT
Total Southwestern Public Service Company					2,438			
Other:								
New Mexico Electric Service Company:								
Maddox	Hobbs	New Mexico	4, 5	GAOT	230	575	Wells	CT
Various Municipals and Co-ops.:								
Various				Various	257	641		
Total other					487			
Net generation additions					2,925			
Purchases from PSA 39					150	250		
Total area 36					3,075			

[1] NOTE.—These two units may be nuclear if the breeder principle proves successful.

TABLE 1–4

Generation Resources for West Region—as of 1970 (Base Year)

Project name	Location: City	Location: State	Unit No.[1]	Type[2]	Capability—mw: Unit(s)[3]	Capability—mw: Project[4]	Thermal units: Source of water supply	Thermal units: Cooling method[5]
Thermal resources in PSA 39:								
Reeves	Albuquerque	New Mexico	1, 2	GAOT	100	----------		
			3	GAOT	75	175	Wells	CT
Person	Albuquerque	New Mexico	1, 2	GAOT	44	----------		
			3, 4	GAOT	70	114	Wells	CT
Prager	Albuquerque	New Mexico	9	GAOT	12	----------		
			5, 7, 8	GAOT	21	33	Wells	CT
Santa Fe	Santa Fe	New Mexico	1, 2	GAOT	13	13	Wells	CT
Algodones	Algodones	New Mexico	1, 2, 3	GAOT	54	54	Wells	CT
Lordsburg	Lordsburg	New Mexico	1	GST	12.5	----------		
			2	GAOT	5.5	----------		
			3	GAOT	11	----------		
			4	GAOT	25	54	Wells	CT
Rio Grande	Anapra	New Mexico	1	GAOT	19.9	----------		
			2	GAOT	28.4	----------		
			3	GAOT	21.5	----------		
			4, 5	GAOT	72.2	----------		
			6, 7	GAOT	98.0	240	Wells	CT
Newman	El Paso	Texas	1	GAOT	86.3	----------		
			2	GAOT	92.4	----------		
			3	GAOT	111.3	290	Wells	CT
Total					973.0	----------		

[1] Unit identification.
[2] OT=Oil Fired Thermal, GAOT=Gas or Oil Fired Thermal, GOT=Geothermal, N=Nuclear, ND=Nuclear-Desalter, D=Diesel, GST=Gas Turbines, GAT=Gas Fired Thermal, CT=Coal Fired Thermal.
[3] Net Capability of Units—Excludes Station Use.
[4] Summation of capability of all units at time of peak demand.
[5] OT=Once through cooling direct from ocean or river, OTP=Once through cooling with cooling ponds, CT=Cooling Towers

TABLE 1–5

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location stream	State	Number of units	Type[1]	Capability megawatts	Hydro energy million kwh median
Hydro resources in PSA 39:						
Elephant Butte	Rio Grande	New Mexico	3	H	22	35
Purchased by PSA 39:						
From PSA 48 (hydro)					87	380
From Area N (thermal)[2]					316	....
Total					403	....

[1] H=Hydro.
[2] Joint ownership project outside area M.

TABLE 1–6

Generation Resources for West Region as of 1980 (Additions Following 1970)

Project name	Location	State	Unit No.[1]	Type [2]	Capability—mw	
					Unit(s) [3]	Project
Thermal resources in PSA 39:						
Newman	El Paso	Texas	4	GAOT	145	435
Thermal—A [4]		Texas	1	GAOT	225 (500)	500
Total					370	....
Purchase from others:						
From area N (thermal resource)					634	1, 037

[1] Unit identification.
[2] GAOT=Gas or Oil Fired Thermal, CT=Coal Fired Thermal.
[3] Net capability of units—excludes station use.
[4] 275 mw available for others.

TABLE 1–7

Generation Resources for West Region—as of 1990 (Additions Following 1980)

Project name	Location	State	Unit No.[1]	Type [2]	Capability—mw	
					Unit(s) [3]	Project
Thermal resources in PSA 39:						
Thermal—A		Texas	2	GAOT	500	1, 000
Thermal—B		New Mexico	1, 2	N	1, 000	1, 000
Thermal—C		Texas	1, 2	GAOT	500	500
Total					2, 000	....

[1] Unit identification.
[2] GAOT=Gas or Oil Fired Thermal, N=Nuclear.
[3] Net capability of units—excludes station use.

TABLE 2–1

PSA 36 Resources Summary Megawatts

Megawatts

	1970	1980	1990
I. Peak Demand (mw) PSA 36 [1]	1700	3320	6080
II. Capacity resources (mw):			
Hydro	0	0	0
Thermal:			
Gas	1872	3585	6510
Gas Turbine	97	127	127
Total	1969	3712	6637
Purchases from others	0	100	250
Sales to others	0	0	0
Total resources	1969	3812	6887
III. Gross margin—capacity resources in excess of peak demand	269	492	807
IV. Maintenance at time of peak	0	0	0
V. Net margin at time of peak	269	492	807
Percent of peak demand	15. 8	14. 8	13. 3

[1] Forecast by utilities in area.

TABLE 2–2

PSA 39 Resources Summary

[Megawatts]

	1970	1980	1990
I. Peak demand—PSA 39 [1]	1, 002	1, 913	3, 646
II. Capacity resources:			
Hydro—conventional	22	22	22
Thermal:			
Gas and oil	960. 5	1, 330. 5	2, 330. 5
Gas turbine	12. 5	12. 5	12. 5
Nuclear			1, 000
Total	973	1, 343	3, 343
Purchases from others [2] (from area N)	403	1, 037	1, 037
Total resources	1, 398	2, 402	4, 402
III. Gross margin—capacity resources in excess of peak demand	396	489	756
IV. Maintenance at time of peak	0	0	0
V. Net margin at time of peak	396	489	756
Percent of peak demand	39. 5	25. 6	20. 7

[1] Combined total forecast by utilities in area.

[2] Includes joint ownership projects outside area M.

TABLE 3–1

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location		Unit No.[1]	Type [2]	Capability—mw		Thermal units	
	City	State			Unit(s) [3]	Project [4]	Source of water supply	Cooling method [5]
Thermal resources in PSA 46:								
Avon	Avon	California	1	GAOT	46	46	Mallard Slough	CT
Contra Costa	Antioch	California	1, 2, 3, 4, and 5	GAOT	581			
			6 and 7	GAOT	678	1259	Suisun Bay	OT
Geysers	Healdsburg	California	1	GOT	11			
			2	GOT	14		Condensed	CT
			3 and 4	GOT	54	79	Steam.	
Humboldt Bay	Eureka	California	1 and 2	GAOT	104		Humboldt Bay	OT
			3	N	50	154		
Hunters Point	S. Francisco	California	1	GAOT	42			
			2 and 3	GAOT	213		San Francisco	
			4	GAOT	163	418	Bay.	OT
Kern	Bakersfield	California	1	GAOT	74			
			2	GAOT	105	179	Wells	CT
Martinez	Martinez	California	1	GAOT	46	46	Mallard Slough	CT
Morro Bay	Morro Bay	California	1 and 2	GAOT	325		Pacific Ocean	OT
			3 and 4	GAOT	676	1001		
Moss Landing	Moss Landing	California	1, 2, 3, 4, and 5	GAOT	583			
			6 and 7	GAOT	1470	2053	Pacific Ocean	OT
Oakland	Oakland	California	1	GAOT	40			
			3	GAOT	14		San Francisco	OT
			4	GAOT	48	102	Bay.	
Oleum	Oleum	California	1 and 2	GAOT	94	94	San Pablo Bay	OT
Pittsburg	Pittsburg	California	1, 2, 3, and 4	GAOT	650		Suisun Bay	OT
			5 and 6	GAOT	649	1299		

[1] Unit identification.

[2] OT=Oil Fired Thermal, GAOT=Gas or Oil Fired Thermal, GOT=Geothermal, N=Nuclear, ND=Nuclear-Desalter, D=Diesel, GST=Gas Turbines, GAT=Gas Fired Thermal, CT=Coal Fired Thermal.

[3] Net capability of units—excludes station use.

[4] Summation of capability of all units at time of peak demand.

[5] OT=Once through cooling direct from ocean or river, OTP=Once through cooling with cooling ponds, CT=Cooling Towers.

TABLE 3–2

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location: City	Location: State	Unit No.[1]	Type[2]	Capability—mw: Unit(s)[3]	Capability—mw: Project[4]	Thermal units: Source of water supply	Thermal units: Cooling method[5]
Potrero	San Francisco	California	1 and 2	GAOT	117		San Francisco	OT
			3	GAOT	204	321	Bay.	
Gas Turbines	Sparks	Nevada	1 and 2	GST	25	25		
Tracy	Sparks	Nevada	1	GAOT	53		Truckee River	OTP
			2	GAOT	87	140		
Fort Churchill	Yerington	Nevada	1	GAOT	110	110	Wells	OTP
Diesel Units	Various	Nevada	(4 units)	D	26	26		
Total						7352		

[1] Unit identification.
[2] OT=Oil Fired Thermal, GAOT=Gas or Oil Fired Thermal, GOT=Geothermal, N=Nuclear, ND=Nuclear-Desalter, D=Diesel, GST=Gas Turbines, GAT=Gas Fired Thermal, CT=Coal Fired Thermal.
[3] Net capability of units—excludes station use.
[4] Summation of capability of all units at time of peak demand.
[5] OT=Once through cooling direct from ocean or river, OTP=Once through cooling with cooling ponds, CT=Cooling Towers.

TABLE 3–3

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location: Stream	Location: State	Number of units	Type[1]	Capability megawatts[2]	Hydro energy (million kwh): Adverse	Hydro energy (million kwh): Median
Hydro resources in PSA 46:							
Pit 1	Pit River	California	2	H	57	236	264
Pit 3	Pit River	California	3	H	71	312	385
Pit 4	Pit River	California	2	H	95	348	422
Pit 5	Pit River	California	4	H	156	675	836
James B. Black	Pit River	California	2	H	153	399	528
Pit 6	Pit River	California	2	H	74	244	337
Pit 7	Pit River	California	2	H	101	344	481
Butt Valley	N.F. Feather River	California	1	H	33	208	84
Caribou	N.F. Feather River	California	5	H	195	752	356
Belden	N.F. Feather River	California	1	H	117	516	245
Bucks Creek	N.F. Feather River	California	2	H	55	102	241
Rock Creek	N.F. Feather River	California	2	H	110	522	483
Cresta	N.F. Feather River	California	2	H	68	328	331
Poe	N.F. Feather River	California	2	H	115	506	512
Drum	Bear River	California	5	H	94	245	280
El Dorado	S.F. American River	California	2	H	21	62	98
Salt Springs	Mokelumne River	California	2	H	31	93	176
Tiger Creek	Mokelumne River	California	2	H	58	203	353
Electra	Mokelumne River	California	3	H	92	200	347
Stanislaus	Stanislaus River	California	1	H	80	241	376
Wishon	N.F. Kings River	California	4	H	20	35	94
Kerckhoff	San Joaquin River	California	3	H	38	171	264
Haas	N.F. Kings River	California	2	H	137	301	395
Balch	N.F. Kings River	California	3	H	139	351	491

[1] H=Hydro, HPS=Pumped Storage Plant, H–HPS=Combination Conventional and Pumped Storage Hydro.
[2] Summation of capability of all units at time of peak demand.

TABLE 3–4

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location: Stream	Location: State	Number of units	Type [1]	Capability megawatts [2]	Hydro energy (million kwh): Adverse	Hydro energy (million kwh): Median
Kings River	N.F. Kings River	California	1	H	42	113	157
Trinity	Trinity River	California	2	H	110	355	270
Spring Creek	Spring Creek	California	2	H	182	467	416
Francis Carr	Clear Creek	California	2	H	156	528	427
Shasta	Sacramento River	California	5	H	466	1, 390	1, 393
Keswick	Sacramento River	California	3	H	67	354	345
Folsom	American River	California	3	H	165	271	534
Oroville-Thermalito	Feather River	California	10	H–HPS	725	917	1, 910
Yuba County Water Agency	M.F. Yuba River	California	3	H	252	830	940
Nevada Irrigation District.	Bear River	California	2	H	59	152	185
Placer County Water Agency.	M.F. American	California	6	H	192	577	586
Union Valley	Silver Creek	California	1	H	32	57	110
Jaybird	Silver Creek	California	2	H	140	315	552
Camino	Silver Creek	California	2	H	150	234	417
Whiterock	S.F. American River	California	2	H	200	257	594
Tri-Dam	Stanislaus River	California	4	H	77	189	400
City and County of San Francisco.	Tuolumne River	California	8	H	267	1, 411	1, 636
Merced Irrigation District.	Merced River	California	2	H	75	214	350
San Luis	San Luis Creek	California	8	HPS	21	119	119
Oroville-Wyandotte Irrigation District.	S.F. Feather River	California	3	H	85	265	335
Minor Hydro:							
P. G. & E.	Various	California	52	H	168	867	1, 184
Others	Various	California	10	H	53	190	398
Total hydro resources					5, 794	17, 466	21, 637
Purchases by PSA 46:							
From Area P					353	1, 504	1, 504

[1] H = Hydro, HPS = Pumped Storage Plant, H–HPS = Combination Conventional and Pumped Storage Hydro.
[2] Summation of capability of all units at time of peak demand.

TABLE 3–5

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location		Unit No.[1]	Type [2]	Capability—MW		Thermal units	
	City	State			Unit(s) [3]	Project [4]	Source of water supply	Cooling method [5]
Thermal resources in PSA 47 and 48:								
Encina	San Diego	California	1–3	GAOT/GST		461	Pacific Ocean	OT
South Bay	San Diego	California	1–3	GAOT		531	Pacific Ocean	OT
Harbor	Wilmington	California	1–5	GAOT		355	Pacific Ocean	OT
Huntington	Huntington Beach	California	1–5	GAOT/GST		990	Pacific Ocean	OT
Haynes	Seal Beach	California	1–6	GAOT		1,580	Pacific Ocean	OT
Redondo	Redondo Beach	California	1–8	GAOT		1,602	Pacific Ocean	OT
Long Beach	Long Beach	California	10 & 11	GAOT		212	Pacific Ocean	OT
Valley	Sun Valley	California	1–4	GAOT		513	Owens River	CT
Scattergood	Playa Del Ray	California	1–2	GAOT		312	Pacific Ocean	OT
Station B	San Diego	California	1–5	GAOT		99		
Silvergate	San Diego	California	1–4	GAOT		244		
Alamitos	Seal Beach	California	1–7	GAOT/GST		2,070	Pacific Ocean	OT
Etiwanda	Etiwanda	California	1–5	GAOT/GST		1,025	MWD	CT
El Segundo	El Segundo	California	1–4	GAOT		1,020	Pacific Ocean	OT
Mandalay	Ventura	California	1–3	GAOT/GST		550	Pacific Ocean	OT
Cool Water	Dagget	California	1–2	GAOT		146	Well	CT
San Bernardino	San Bernardino	California	1–2	GAOT		130	Local	CT
High Grove	Colton	California	1–4	GAOT		154	Local	CT
Yucca	Yuma	Arizona	1	GAOT		75	Wells	CT
Saguaro	Red Rock	Arizona	1–2	GAOT		250	Wells	CT
Ocotillo	Tempe	Arizona	1–2	GAOT		227	Wells	CT

[1] Unit identification.
[2] OT=Oil Fired Thermal, GAOT=Gas or Oil Fired Thermal, GOT=Geothermal, N=Nuclear, ND=Nuclear-Desalter, D=Diesel, GST=Gas Turbines, GAT=Gas Fired Thermal, CT=Coal Fired Thermal.
[3] Net capability of units—excludes station use.
[4] Summation of capability of all units at time of peak demand.
[5] OT=Once through cooling direct from ocean or river, OTP=Once through cooling with cooling ponds, CT=Cooling Towers.

TABLE 3–6

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location: City	Location: State	Unit No.[1]	Type [2]	Capability—MW: Unit(s) [3]	Capability—MW: Project [4]	Thermal units: Source of water supply	Thermal units: Cooling method [5]
4 Corners	Farmington	New Mexico	1-5	CT		2,220	San Juan River	OTP
Apache	Cochise	Arizona	1 & 2	GAT/D		85	Wells	CT
Irvington	Tucson	Arizona	1-4	GAOT/D		423	Wells	CT
Kyrene	Tempe	Arizona	1 & 2	GAT		108	Irrigation Canal	CT
Cholla	Joseph City	Arizona	1	CT		115	Wells	CT
El Centro	El Centro	California	1-3	GAOT		181	Canal.	
Brawley	Brawley	California	1-10	D		36		
Clark	East Las Vegas	Nevada	1-3	GAOT		201	Sewage Effluent	CT
Reid Gardner	Moapa	Nevada	1 & 2	CT		254	Well	CT
Westside Diesel	Las Vegas	Nevada	1-11	D		29	None	Air
Mohave	Bullhead City (Arizona).	Nevada	1	CT		790	Colorado River	CT
San Onofre	San Clemente	California	1	N		450	Pacific Ocean	OT
Burbank	Burbank	California	1-8	GAOT		209	Local	CT
Pasadena	Pasadena	California	1-6	GAOT		230	Local	CT
Glendale	Glendale	California	1-5	GAOT		148	Local	CT
Sunrise	Las Vegas	Nevada	1	GAOT		86	Sewage Effluent	CT
De Moss-Petrie	Tucson	Arizona	1-4	GAOT		101	Wells	CT
Cross Cut	Tempe	Arizona	1 & 2	GAT		37	Irrigation Canal	CT
Agua Fria	Glendale	Arizona	1 & 2	GAT		411	Wells	CT
Hayden	Northwestern	Colorado	1	CT		150	Artificial Lake	CT
Phoenix	Phoenix	Arizona	4, 5, 6	GAOT		111	Wells	CT
Total Thermal (PSA 47 and 48)						18,921		

[1] Unit identification.
[2] OT=Oil Fired Thermal, GAOT=Gas or Oil Fired Thermal, GOT=Geothermal, N=Nuclear, ND=Nuclear-Desalter, D=Diesel, GST=Gas Turbines, GAT=Gas Fired Thermal, CT=Coal Fired Thermal.
[3] Net capability of units—excludes station use.
[4] Summation of capability of all units at time of peak demand.
[5] OT=Once through cooling direct from ocean or river, OTP=Once through cooling with cooling ponds, CT=Cooling Towers.

356-240 O—70——27

TABLE 3–7

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location—city or river	State	Number of units	Type [1]	Capability megawatts [2]
Hydro resources in PSA 47 and 48:					
Big Creek	San Joaquin	California	21	H	690
Bishop Hydro	Bishop Creek	California	16	H	52
Dry Canyon	Aquaduct	California	1	H	12
Hoover	Colorado	Arizona	17	H	1345
Knob	Winterhaven	California	6	H	68
San Francisquito	Newhall	California	8	H	108
Gorge	Owens	California	3	H	113
Base Hydro	Various	California	39	H	100
Davis	Colorado	California		H	225
Glen Canyon	Colorado	California		H	450
Parker	Colorado	California		H	120
Stewart Mtn	Salt River	Arizona	1	H	13
Cross Cut	Cross Cut Canal	Arizona	1	H	4
Roosevelt	Salt River	Arizona	3	H	24
Horse Mesa	Salt River	Arizona	3	H	34
Mormon Flat	Salt River	Arizona	1	H	13
Total hydro (PSA 47 and 48)					3371
Purchased by PSA 47 and 48:					
From area P					1101
Sales by PSA 48 [3]:					
To PSA 41—65 mw hydro					
To PSA 39—87 mw hydro and 316 mw thermal					468

[1] H=Hydro, HPS=Pumped Storage Plant, H–HPS=Combination Conventional and Pumped Storage Hydro.
[2] Summation of capability of all units at time of peak demand.
[3] Either firm power or contractual arrangement involving a specific project.

TABLE 3–8

Generation Resources for West Region as of 1980 (Additions and Deductions Following 1970)

Project name	Location: Stream (if hydro); City (if thermal)	Location: State	Unit No. [1]	Type [2]	Capability—mw: Unit(s) [3]	Capability—mw: Project [4]
Thermal resources in PSA 46:						
Geysers	Healdsburg	California	5, 6, 7, 8, 9, 10, 11, 12, and 13.	GOT	450	529
Diablo Canyon	San Luis Obispo	California	1 and 2	N	2, 120	2, 120
Rancho Seco	Sacramento	California	1, 2, and 3.	N	2, 400	2, 400
Delta	San Francisco Bay Area	California	1, 2, and 3.	N	3, 180	3, 180
San Francisco Conventional.	San Francisco Bay Area	California	1	GAOT	325	325
Medocino	Point Arena	California	1	N	1, 060	1, 060
Suburban	San Francisco Bay Area	California	1 and 2	N	2, 120	2, 120
Thermal A	South Coast	California	1	N	1, 060	1, 060
Oakland	Oakland	California	1, 3, and 4.	GAOT	(−102)	0
Hunters Point	San Francisco	California	1	GAOT	(−42)	376
Fort Churchill	Yerington	Nevada	2, 3, and 4.	GAOT	330	440
Tracy	Sparks	Nevada	3 and 4	GAOT	500	587
Total					13, 401	....

[1] Unit identification or number of hydro units at site.

[2] H=Hydro, HPS=Pumped Storage Plant, H–HPS=Combination Conventional and Pumped Storage Hydro, GAT =Gas Fired Thermal, CT=Coal Fired Thermal, OT=Oil Fired Thermal, GAOT=Gas or Oil Fired Thermal, GOT =Geothermal, N=Nuclear, NB=Nuclear Breeder, ND=Nuclear Desalter, D=Diesel, GST=Gas Turbines.

[3] Change in net capability of units. For hydro units, capability at time of peak demand (adverse water conditions).

[4] Summation of capability of all units at time of peak demand.

TABLE 3–9

Generation Resources for West Region as of 1980 (Additions and Deductions Following 1970)

Project name	Location: Stream (if hydro); City (if thermal)	Location: State	Unit No.[1]	Type [2]	Capability—mw: Unit(s) [3]	Capability—mw: Project [4]	Hydro energy (million kwh) [5]: Adverse	Hydro energy (million kwh) [5]: Median
Hydro Resources in PSA 46:								
						45		
Don Pedro	Tuolumne River	California	3 units	H	132	132	310	581
Auburn	N.F. American River.	California	3 units	H	300	300	157	424
Melones	Stanislaus	California	1 unit	H	137	150	354	419
Nashville	Consumnes	California	2 units	H	20	20	40	74
Robbs Peak	Silver Creek	California	1 unit	H	17	25	0	0
Loon Lake	S.F. Rubicon River.	California	1 unit	H	80	80	31	90
Marysville	Yuba River	California	1 unit	H	50	50	150	250
Northern California—coastal.	Various	California	2 units	H	150	150	396	396
San Luis	San Luis Creek	California	8 units	HPS	85	106	192	192
Minor Hydro:								
P.G. & E.					(−13)	(−13)	(−48)	(−102)
Others					(−19)	(−19)	(−65)	(−190)
Total					939	....	1, 517	2, 134
Purchases by PSA 46:								
From Area P					47	400	847	847

[1] Unit identification or number of hydro units at site.

[2] H = Hydro, HPS = Pumped Storage Plant, H-HPS = Combination Conventional & Pumped Storage Hydro, GAT = Gas Fired Thermal, CT = Coal Fired Thermal, OT = Oil Fired Thermal, GAOT = Gas or Oil Fired Thermal, GOT = Geothermal N = Nuclear, NB = Nuclear Breeder, ND = Nuclear Desalter, D = Diesel, GST = Gas Turbines.

[3] Change in net capability of units. For hydro units, capability at time of peak demand (adverse water conditions).

[4] Summation of capability of all units at time of peak demand.

[5] Energy associated with change in capability.

TABLE 3-10

Generation Resources for West Region as of 1980 (Additions and Deductions Following 1970)

Project name	Location: Stream (if hydro); City (if thermal)	Location: State	Unit No.[1]	Type[2]	Capability—(mw): Unit(s)[3]	Capability—(mw): Project[4]
Thermal resources in PSA 47 and 48:						
Harbor	Wilmington	California	1–5	GAOT	(355)	0
Thermal J		New Mexico	1 and 2	CT	2, 100	2, 100
Mohave	Bullhead City (Ariz.)	Nevada	2	CT	790	1, 580
Ormond Beach	Santa Clara	California	1	GAOT	790	790
Thermal D		California	1 and 2	GAOT	2, 090	2, 090
Bolsa Island	Huntington Beach	California	1, 2, 3	ND	1, 970	1, 970
Thermal A		California	1 and 2	CT	1, 580	1, 580
Thermal B		California	1	N	1, 050	1, 050
Thermal K		California	1 and 2	N	2, 000	2, 000
Thermal L		Inland	1, 2, 3	CT	2, 370	2, 370
Local Diesel	Various	Arizona and California.		D	100	100
Gas Turbines	Various	Arizona and California.	11 units	GST	1, 398	
Long Beach	Long Beach	California	10 and 11	GAOT	(212)	0
Thermal H		Arizona and Nevada.	1	GAOT	800	800
Sunrise	Las Vegas	Nevada	2	GAOT	120	206
Reid Gardner	Moapa	Nevada	3	GAOT	150	404
San Juan	Fruitland	New Mexico	1, 2, 3	CT	960	960
Total					17, 701	

[1] Unit identification or number of hydro units at site.

[2] H = Hydro, HPS = Pumped Storage Plant, H-HPS = Combination Conventional and Pumped Storage Hydro, GAT = Gas Fired Thermal, CT = Coal Fired Thermal, OT = Oil Fired Thermal, GAOT = Gas or Oil Fired Thermal, GOT = Geothermal, N = Nuclear, NB = Nuclear Breeder, ND = Nuclear Desalter, D = Diesel, GST = Gas Turbines.

[3] Change in net capability of units. For hydro units, capability at time of peak demand (adverse water conditions).

[4] Summation of capability of all units at time of peak demand.

TABLE 3–11

Generation Resources for West Region as of 1980 (Additions and Deductions Following 1970)

Project name	Location		Unit No.[1]	Type [2]	Capability (mw)	
	Stream (if hydro); City (if thermal)	State			Unit(s) [3]	Project [4]
Hydro Resources In PSA 47 and 48:						
Castaic	State Aqueduct	California	4	H–HPS	747	747
Pumped Storage		California	4	HPS	1, 000	1, 000
Glen Canyon	Colo. River	Arizona		H	450	900
Total					2, 197	
Purchase By PSA 47 and 48:						
From Area P					1, 399	2, 500
Sales by PSA 48: [5]						
To PSA 41—52 mw hydro.						
To PSA 39—634 mw thermal					686	1, 154

1 Unit identification or number of hydro units at site.

2 H = Hydro, HPS = Pumped Storage Plant, H–HPS = Combination Conventional and Pumped Storage Hydro, GAT = Gas Fired Thermal, CT = Coal Fired Thermal, OT = Oil Fired Thermal, GAOT = Gas or Oil Fired Thermal, GOT = Geothermal, N = Nuclear, NB = Nuclear Breeder, ND = Nuclear Desalter, D = Diesel, GST = Gas Turbines.

3 Change in net capability of units. For hydro units, capability at time of peak demand (adverse water conditions).

4 Summation of capability of all units at time of peak demand.

5 Either firm power or contractural arrangement involving a specific project.

TABLE 3–12

Generation Resources for West Region as of 1990 (Additions and Deductions Following 1980)

Project name	Location: Stream (if hydro); City (if thermal)	Location: State	Unit No.[1]	Type[2]	Capability—mw: Unit(s)[3]	Capability—mw: Project[4]
Thermal resources in PSA 46:						
Geysers	Healdsburg	California	14, 15, 16, 17, 18.	GOT	250	779
Potrero	San Francisco	California	1 and 2	GAOT	(−117)	204
S.F. Conventional	San Francisco Bay Area	California	2, 3	GAOT	650	975
Thermal A	South Coast	California	2	N	1, 060	....
			3 and 4	N	3, 000	5, 120
Thermal B	South Coast	California	1, 2	N	3, 000	3, 000
Suburban	San Francisco Bay Area	California	3	N	1, 060	....
			4, 5, 6, 7	N	6, 000	9, 180
Delta	San Francisco Bay Area	California	4, 5, 6	N	3, 150	....
			7	N	1, 500	7, 830
Mendocino	Point Arena	California	2, 3	N	3, 000	4, 060
Peaking Thermal	San Francisco Bay Area	California	4 units	GST	400	....
			9 units	GST	1, 350	1, 750
Sierra	Not known	Nevada	1 and 2	CT	600	....
			3, 4, and 5.	CT	1, 500	2, 100
Total					26, 403	....

[1] Unit identification or number of hydro units at site.

[2] H = Hydro, HPS = Pumped Storage Plant, H–HPS = Combination Conventional and Pumped Storage Hydro, GAT = Gas Fired Thermal, CT = Coal Fired Thermal, OT = Oil Fired Thermal, GAOT = Gas or Oil Fired Thermal, GOT = Geothermal, N = Nuclear, NB = Nuclear Breeder, ND = Nuclear Desalter, D = Diesel, GST = Gas Turbines.

[3] Change in net capability of units. For hydro units, capability at time of peak demand (adverse water conditions).

[4] Summation of capability of all units at time of peak demand.

TABLE 3-13

Generation Resources for West Region as of 1990 (Additions and Deductions Following 1980)

Project name	Location: Stream (if hydro); City (if thermal)	Location: State	Unit No.[1]	Type[2]	Capability—mw: Unit(s)[3]	Capability—mw: Project[4]	Hydro energy (million kwh)[5]: Adverse	Hydro energy (million kwh)[5]: Median
Hydro resources in PSA 46:								
Hydro Pumped Storage 1.	Northern California.	California	4 units	HPS	1000	1000	(−188)	(−188)
Northern California Coastal.	Northern California.	California	....	H	1500	1650	3940	3940
Hydro 1	Stanislaus River	California		H	170	170	440	580
Hydro Pumped Storage 2.	Central California.	California	4 units	HPS	1000	1000	(−188)	(−188)
Auburn	N.F. American River.	California	4 units	H	100	400	0	0
Total					3770	....	4004	4144
Purchases by PSA 46:								
From Area P					700	1100	(−3597)	(−3597)

[1] Unit identification or number of hydro units at site.

[2] H = Hydro, HPS = Pumped Storage Plant, H–HPS = Combination Conventional and Pumped Storage Hydro, GAT = Gas Fired Thermal, CT = Coal Fired Thermal, OT = Oil Fired Thermal, GAOT = Gas or Oil Fired Thermal, GOT = Geothermal, N = Nuclear, NB = Nuclear Breeder, ND = Nuclear Desalter, D = Diesel, GST = Gas Turbines.

[3] Change in net capability of units. For hydro units, capability at time of peak demand (adverse water conditions).

[4] Summation of capability of all units at time of peak demand.

[5] Energy associated with change in capability.

TABLE 3–14

Generation Resources for West Region as of 1990 (Additions and Deductions Following 1980)

Project name	Location: Stream (if hydro); City (if thermal);	Location: State	Unit number [1]	Type [2]	Capability (mw): Unit(s) [3]	Capability (mw): Project [4]
Thermal resources in PSA 47 and 48:						
Thermal D	Coastal	California	3	N	1,300	....
			4 and 5	N	3,100	6,490
Thermal B	Coastal	California	2, 3, 4	N	3,150	4,200
Thermal C	South Coast	California	1 and 2	N	2,500	....
			3, 4, 5	N	4,500	7,000
Gas Turbines	Various	California, Arizona, and Nevada.	....	GST	2,483	....
North Coast	Lompoc	California	1–4	N	6,000	6,000
Clark	East Las Vegas	Nevada	1	GAOT	(51)	150
Thermal M		Inland	1, 2, 3, 4.	CT	5,200	5,200
Thermal E		California	1–3	N	3,750	3,750
Phoenix	Phoenix	Arizona	4, 5, 6	GAOT	(111)	0
Redondo	Redondo Beach	California	1, 2, 3, 4.	GAOT	(295)	1,307
Local Diesel	Various	Arizona and California.	....	D	100	100
Thermal F	Undesignated	California	1–6	N	8,000	8,000
Thermal G	Undesignated	Arizona	1	N	1,000	1,000
Thermal H	Various	Arizona and Nevada.	2–3	GAOT	1,000	1,800
					41,626	....
Hydro resources in PSA 47 and 48:						
Castaic	State Aqueduct	California	2	H–HPS	460	1,207
Pumped Storage 2		California	4	HPS	1,000	1,000
Pumped Storage 3		California	4	HPS	1,000	1,000
Miscellaneous			1	H	15	15
Total					2,475	....

[1] Unit identification or number of hydro units at site.

[2] H = Hydro, HPS = Pumped Storage Plant, H–HPS = Combination Conventional and Pumped Storage Hydro, GAT = Gas Fired Thermal, CT = Coal Fired Thermal, OT = Oil Fired Thermal, GAOT = Gas or Oil Fired Thermal, GOT = Geothermal, N = Nuclear, NB = Nuclear Breeder, ND = Nuclear Desalter, D = Diesel, GST = Gas Turbines.

[3] Change in net capability of units. For hydro units, capability at time of peak demand (adverse water conditions).

[4] Summation of capability of all units at time of peak demand.

TABLE 4

Area N Resource Summary

	1970	1980	1990
I. Peak demand (Mw):			
PSA 46	11, 200	24, 100	51, 600
PSA 47	13, 300	27, 700	55, 000
PSA 48	4, 490	9, 570	20, 600
Total [1]	28, 990	61, 370	127, 200
II. Capacity resources			
Hydro: [2]	*Mw*	*Mw*	*Mw*
Conventional [3]	9, 144	11, 195	13, 440
Pumped storage	21	1, 106	5, 106
Total	9, 165	12, 301	18, 546
Thermal:			
Gas and oil	21, 321	25, 715	26, 791
Coal	3, 529	11, 329	18, 629
Nuclear	500	17, 460	72, 530
Gas turbine	679	2, 077	6, 310
Diesel	165	265	365
Geothermal	79	529	779
Total	26, 273	57, 375	125, 404
Purchases from others	1, 454	2, 900	3, 600
Sales to others	468	1, 154	1, 154
Total resources	36, 424	71, 422	146, 396
III. Gross Margin—Capacity resources in excess of peak demand	7, 524	10, 052	19, 196
IV. Maintenance at time of peak	338	0	0
V. Net margin at time of peak	7, 186(4)	10, 052	19, 196
Percent of peak demand	24. 9	16. 4	15. 1

[1] FPC Load Forecasts of February 1968.

[2] Capacity for Month of Peak Demand Assuming Adverse Hydro Conditions.

[3] Includes Combined Conventional and Pumped Storage Projects.

[4] This margin results from using the FPC load forecast in combination with firm resource commitments. The FPC load forecast is lower than that predicted by utility companies involved and, therefore, results in a margin considerably greater than actually expected.

TABLE 5–1

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location: City	Location: State	Unit No.[1]	Type[2]	Capability—mw project[3]	Thermal units: Source of water supply	Thermal units: Cooling method[4]
Thermal resources in PSA 31 and 32:							
Arapahoe	Denver	Colorado	1, 2, 3, 4	GAT, CT	240	Wells and South Platte River.	CT
Zuni	Denver	Colorado	1, 2	GAOT, CT	107	South Platte River.	CT
Cherokee	Denver	Colorado	1, 2, 3, 4	GAT, CT	724	South Platte River.	CT
Valmont	Denver	Colorado	1, 2, 3, 4, 5	GAT, CT	300	Boulder Creek	OTP (lake)
Hayden	Hayden	Colorado	1	CT	160	Yampa River	CT
Nucla	Nucla	Colorado	1, 2, 3	CT	39	San Miguel River.	OTP
Cameo	Cameo	Colorado	1, 2	GAT, CT	70	Colorado River.	OT
Animas	Farmington	New Mexico.		CT	31		
Drake	Colorado Springs.	Colorado	1, 2, 3, 4, 5, 6	GAT, CT	151	South Platte River.	CT
Birdsdale	Colorado Springs.	Colorado	1, 2, 3	GAT, CT	57	South Platte River.	CT
Pueblo	Pueblo	Colorado	4, 5, 6	GAT, CT	35	Arkansas River	CT
Clark	Canon City	Colorado	1, 2	CT	41	Arkansas River	
Alamosa	Alamosa	Colorado	3, 4, 5, 6	GAOT, CT	21	Rio Grande River.	CT
Dave Johnston	Glenrock	Wyoming	1, 2, 3	CT	444	North Platte River.	OTP
Scotts Bluff	Scotts Bluff	Nebraska			44		
Minor (less than 15 mw)					242		
Subtotal thermal PSA 31 and 32					2, 706		

[1] Unit identification

[2] OT = Oil Fired Thermal, GAOT = Gas or Oil Fired Thermal, GOT = Geothermal, N = Nuclear, ND = Nuclear Desalter, D = Diesel, GST = Gas Turbines, GAT = Gas Fired Thermal, CT = Coal Fired Thermal.

[3] Summation of capability of all units of time of peak demand.

[4] OT = once through cooling direct from river, OTP = once through cooling with cooling ponds, CT = cooling towers.

TABLE 5–2, 5–3

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location stream	State	Number of units	Type [1]	Capability [2] megawatts	Hydro energy (million kwh)	
						Adverse	Median
Hydro Resources in PSA 31 and 32:							
Williams Fork	Williams Fork	Colorado		H	3		
Green Mountain	Blue River	Colorado	2	H	26		
Marys Lake	(3)	Colorado	1	H	9		
Estes	(3)	Colorado	3	H	54		
Pole Hill	(3)	Colorado	1	H	35		
Flatiron	(3)	Colorado	3	H	82		
Big Thompson	(3)	Colorado	1	H	5		
Seminoe	North Platte River	Wyoming	3	H	39		
Kortes	North Platte River	Wyoming	3	H	40		
Fremont Canyon	North Platte River	Wyoming	2	H	48	1, 497	1, 602
Alcova	North Platte River	Wyoming	2	H	40		
Glendo	North Platte River	Wyoming	2	H	15		
Guernsey	North Platte River	Wyoming	2	H	6		
Shoshone	Shoshone River	Wyoming	3	H	6		
Heart Mountain	Shoshone River	Wyoming	1	H	7		
Boysen	Wind River	Wyoming	2	H	16		
Pilot Butte	Wind River	Wyoming	2	H	2		
Lower Molina	Plateau Creek	Colorado	1	H	5	40	66
Upper Molina	Plateau Creek	Colorado	1	H	9		
Blue Mesa	Gunnison River	Colorado	2	H	60	170	283
Morrow Point	Gunnison River	Colorado	2	H	120	264	402
Fontenelle	Green River	Wyoming	1	H	10	13	55
Boulder Canyon	Boulder Creek	Colorado	2	H	20	20	40
Cabin Creek	Clear Creek	Colorado	2	HPS	324	−40	−40
Shoshone	Colorado River	Colorado	2	H	13	100	100
Palisades	Colorado River	Colorado	2	H	3	15	20
Redlands	Colorádo River	Colorado	1	H	1		
Tacoma	Animas River	Colorado	1, 2, 3	H	8		
Ames	San Miguel River	Colorado	1	H	4	[4] 50	[4] 75
Maintou Spring	Fountain Creek	Colorado		H	5		
Strawberry	Salt River	Wyoming		H	1		
Minor (less than 1 mw)					6		
Subtotal hydro PSA 31 and 32					1022	2, 129	2, 603

[1] H = Hydro, HPS = Pump Storage Plant, H–HPS = Combination Conventional and Pumped Storage Hydro.

[2] Summation of capability of all units at time of peak demand.

[3] These plants are located along the eastern slopes of the Rocky Mountains on a transmountain diversion of water from the headwaters of the Colorado River to the South Platte River.

[4] Energy figures not available. Values shown are estimated.

TABLE 5–4

Generation Resources for West Region as of 1980 (Additions and Deductions Following 1970)

Project name	Location: Stream (if hydro); City (if thermal)	Location: State	Unit No.	Type	Capability—mw: Unit(s)	Capability—mw: Project	Hydro energy (million kwh): Adverse	Hydro energy (million kwh): Median
Thermal resources PSA 31 and 32:								
Fort St. Vrain	Platteville	Colorado	1	N	330	330		
Unassigned		Colorado	1, 2	GAT, CT	700	700		
Unassigned		Colorado	1, 2	GAT, CT	700	700		
Unassigned		Colorado	1	CT	500	500		
Dave Johnston	Glenrock	Wyoming	4	CT	330	774		
Unassigned		Wyoming		CT	500	500		
Total thermal PSA 31 and 32.					3, 060			
Hydro resources PSA 31 and 32:								
Crystal	Gunnison	Colorado	1	H	28	28	133	168
Elbert	Trans Mount Diversion (near Leadville, Colo.).	Colorado	1	H–HPS	100	100	153	153
Otero	Trans Mount Diversion (near Leadville, Colo.).	Colorado	1	H	11	11	17	17
Total Hydro PSA 31 and 32.					139		303	338

TABLE 5–5

Generation Resources for West Region as of 1990 (Additions and Deductions Following 1980)

Project name	Location: Stream (if hydro); city (if thermal)	Location: State	Unit No.	Type	Capability—mw: Unit(s)	Capability—mw: Project	Hydro energy (million kwh): Adverse	Hydro energy (million kwh): Median
Thermal resources								
PSA 31 and 32:								
Unassigned		Colorado	1, 2	CT	1, 000	1, 000		
Unassigned		Colorado	1, 2	CT	1, 000	1, 000		
Unassigned		Colorado	1	N or CT	1, 000	1, 000		
Unassigned		Colorado	1	N or CT	1, 000	1, 000		
Unassigned		Wyoming or Western Nebraska.	1, 2	CT	850	850		
Unassigned		Wyoming	1	CT	500	500		
Unassigned		Wyoming	1	CT	500	500		
Total thermal PSA 31 and 32.					5, 850			
Hydro resources								
PSA 31 and 32:								
Elbert	Trans. Mount Diversion.	Colorado	2	H–HPS	100	200	153	153
Two Forkes	South Platte	Colorado	1	H	150	150	150	150
Total hydro PSA 31 and 32.					250		303	303

TABLE 6

Area O Resource Summary Megawatts

	1970	1980	1990
I. Peak demand:			
PSA 31	715	1, 570	3, 150
PSA 32	2, 130	4, 230	8, 030
Total [1]	2, 845	5, 800	11, 180
II. Capacity resource:			
Hydro: [2]			
Conventional [3]	698	837	1, 087
Pump storage	324	324	324
Total	1, 022	1, 161	1, 411
Thermal:			
Gas and coal	1, 577	2, 977	2, 977
Coal	715	2, 045	5, 895
Gas, oil, and coal	128	128	128
Diesel	135	135	135
Nuclear		330	[4] 2, 330
Miscellaneous	151	151	151
Total	2, 706	5, 766	11, 616
Exchange with other areas	0	0	0
Total resources	3, 728	6, 927	13, 027
IV. Maintenance at time of peak	0	0	0
V. Net margin at time of peak	883	1, 127	1, 847

[1] FPC Load Forecasts of February 1968.
[2] Capacity for month of peak demand assuming adverse hydro conditions.
[3] Includes combined conventional and pumped storage projects.
[4] The nuclear additions shown for 1990 could be either coal fired or nuclear plants depending on economics at the time of installation.

TABLE 7–1

FPC West Regional Advisory Committee Task Force on Generation—Region P—Resources Existing by 1970–71—Power Supply Area 30

	January peak mw	Energy average mw		Ownership
		Critical period	Median average hydro	
PROJECT—RIVER				
Hungry Horse, South Fork	271	185	101	USBR
Kerr, Clark Fork	180	112	123	MPCo
Thompson Falls, Clark Fork	40	35	35	MPCo
Madison, Madison	9	7	8	MPCo
Canyon Ferry, Mo	58	29	46	USBR
Hauser Lake, Mo	16	12	14	MPCo
Holter, Mo	49	24	29	MPCo
Black Eagle, Mo	18	14	17	MPCo
Rainbow, Mo	35	29	35	MPCo
Cochrane, Mo	50	24	33	MPCo
Ryan, Mo	60	42	53	MPCo
Morony, Mo	49	25	33	MPCo
Ft. Peck, Mo	200	97	100	Corps of E.
Mystic Lake, Rosebud	12	7	6	MPCo
Yellowtail, Big Horn	250	108	126	USBR
Minor plants	4	3	3	MPCo
Total hydro	1, 301	753	762	
STEAM PLANTS—LOCATION				
Bird, Billings	66	60	60	MPCo
Billings Unit No. 2, Billings	180	144	144	MPCo
Total steam	246	204	204	
Total resources	1, 547	957	966	

TABLE 7–2

WRAC Generation Task Force PSA 30 (Montana) Estimated Resources

	1970		1980		1990	
	Peak	Average	Peak	Average	Peak	Average
Hydro:						
Committed:						
Hungary Horse	271	185	68	97	68	95
Libby			216	204	216	200
Kerr	180	123	180	123	180	123
Thompson Falls	40	35	40	35	40	35
Madison	9	8	9	8	9	8
Canyon Ferry	58	46	58	46	58	46
Hauser Lake	16	14	16	14	16	14
Holter	49	29	49	29	49	29
Black Eagle	18	17	18	17	18	17
Rainbow	35	35	35	35	35	35
Cochrane	50	33	50	33	50	33
Ryan	60	53	60	53	60	53
Morony	49	33	49	33	49	33
Ft. Peck	200	100	200	100	200	100
Mystic Lake	12	6	12	6	12	6
Yellowtail	250	126	250	126	250	126
Minor plants	4	3	4	3	4	3
Total	1, 301	846	1, 314	962	1, 314	956
Noncommitted:						
Libby					339	
Buffalo Rapids			267	119	267	119
Kootenai Falls			414	115	414	115
Spruce Park					134	32
Smoky Range					195	56
Lower Flathead						
Nine Mile Prairie					92	19
Quartz Creek					120	39
Libby Rereg					70	45
Total	0	0	681	234	1, 631	425
Thermal:						
Conventional:						
Committed	246	204	246	204	246	204
Noncommitted			400	340	2, 000	1, 700
Total	246	204	646	544	2, 246	1, 904

356–240 O—70——28

TABLE 7–3

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location		Units	Type [1]	Capability (mw)		Water source	Cooling method [2]
	City	State			Units	Project		
Thermal resources in PSA 41:								
Gadsby	Salt Lake	Utah	3	GAT, OT, CT	241	241	Jordan River	CT
Jordan	Salt Lake	Utah	1	OT	25	25	Jordan River	OT
Hale	Orem	Utah	2	GAT, CT	64	64	Provo River	OT
Carbon	Castle Gate	Utah	2	CT	166	166	Price River	CT
Naughton	Kemmerer	Wyoming	2	CT	380	380	Hamms Fork	CT
Miscellaneous small plants.	Various	Utah		Various	26	26		
Miscellaneous small plants.	Various	Utah, Idaho Wyo., Nev.		IC	41	41		
Total					943			

[1] GAT = Gas Thermal, OT = Oil (Pitch Thermal), CT = Coal Thermal, IC = Internal Combustion.
[2] CT = Cooling Tower, OT = Once Through.

TABLE 7–4

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location		Number of units	Type	Capability megawatts	Energy (kwh 10^6)	
	Stream	State				Adverse	Median
Hydro resources in PSA 41:							
American Falls	Snake	Idaho	5	H	26	122	146
Grace	Bear	Idaho	5	H	40	135	85
Oneida	Bear	Idaho	3	H	30	56	63
Palisades	Snake	Idaho		H	114	41	65
Upper Salmon	Snake	Idaho	4	H	36	306	313
Lower Salmon	Snake	Idaho	4	H	66	240	257
Bliss	Snake	Idaho	3	H	77	349	379
C.J. Strike	Snake	Idaho	3	H	87	457	504
Brownlee	Snake	Idaho	4	H	450	1, 980	2, 689
Oxbow	Snake	Idaho	4	H	220	909	1, 154
Hells Canyon	Snake	Idaho	3	H	425	1, 663	2, 112
Cutler	Bear	Utah	2	H	29	39	102
Flaming Gorge	Green	Utah		H	108	295	452
Miscellaneous small plants	Various	Idaho		H	103	122	135
Miscellaneous small plants	Various	Utah		H	57	138	246
Total					[1] 1, 868	6, 852	8, 702

[1] USBR Plants in Southern Idaho dedicated to Project Pumping are not included—Minidoka, Anderson Ranch, Black Canyon and Boise Diversion.

TABLE 7–5

Generation Resources for West Region as of 1980 and 1990

Project name	Location: City	Location: State	Units	Type	Capability (mw): Units	Capability (mw): Project	Water source	Cooling method
Additional resources in service 1970–1980:								
PSA 41:								
Naughton	Kemmerer	Wyoming		CT	330	710	Hamms Fork	CT
Southeast Utah					1, 500	1, 500		
Southwest Idaho					400	400		
Eastern Idaho					1, 200	1, 200		
Total					3, 430	....		
Additional resources in service 1980–1990:								
PSA 41:								
Southwest Idaho					1, 500	1, 900		
Eastern Idaho					1, 800	3, 000		
Northern Utah					3, 000	3, 000		
Total					6, 300	....		

TABLE 8-1

WRAC Generation Task Force PSA 30 (Montana)—Load and Generation Projections—Peak Megawatts

	1970	1980	1990
Peak load:			
PSA 30 (Montana)	1, 460	2, 590	4, 700
Exports or imports [1]	+91	−137	+22
Net peak load	1, 551	2, 453	4, 722
Peak resources:			
Hydro:			
Committed	1, 301	1, 314	1, 314
Noncommitted	0	681	1, 631
Total	1, 301	1, 995	2, 945
Thermal:			
Conventional:			
Committed	246	246	246
Noncommitted	0	400	2, 000
Nuclear:			
Committed	0	0	0
Noncommitted	0	0	0
Gas Turbine:			
Committed	0	0	0
Noncommitted	0	0	0
Total	246	646	2, 246
Total resources	1, 547	2, 641	5, 191
Reserves required (−)	−146	−259	−470
Net generation for load	1, 401	2, 382	4, 721
Surplus (+) or deficit (−)	−150	−71	−1
Interruptible load included [2]	40	40	40

[1] Detail of Exports (+) or Imports (−):

	1970	1980	1990
West	−367	−556	−326
East	458	+419	+348
Total	+91	−137	+22

[2] MPCo.

TABLE 8-2

Generation Resources West Region as of 1970, 1980, and 1990

	1970 (existing)	1980	1990
LOAD PROJECTION (MW)			
Idaho area load	1, 753	3, 510	7, 076
Utah area load	1, 087	2, 180	4, 384
Total area 41	2, 840	5, 690	11, 460
	FPC load projections[1]		
USBR project pumping	9		
(Pumping in excess of generation—not included in FPC load projections.)			
GENERATION PROJECTION (MW)			
Summary area 41:			
Hydro (existing)	1, 868	1, 868	1, 868
Steam (existing)	943	943	943
New generation (Idaho area)[2]		1, 600	4, 900
New generation (Utah area)[2]		1, 830	4, 830
Transfer in[3]	415	117	117
Total area 41	3, 226	6, 358	12, 658

[1] FPC Load Forecasts of February 1968.

[2] New generation is expected to be principally thermal—generally coal fired with cooling towers. With the large deposits of fossil fuel available in this area, and with the higher costs for smaller nuclear units (less than 750 mw), nuclear plants do not appear, at the present time, to be economically attractive for Area 41 until the 1980's.

[3] 350 mw "Transfer In" from Area P West Group during 1970—balance of "Transfer In" is from PSA 48 Glen Canyon for CRSP Preference Users in Utah.

TABLE 9–1

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location: City	Location: State	Number of units [1]	Type [2]	Capability—mw: Unit(s) [3]	Capability—mw: Project [4]	Thermal units: Source of water supply	Thermal units: Cooling method [5]
Thermal Resources in PSA 42, 43, 44, and 45:								
City of Eugene	Eugene	Oregon	1, 2, and 3	OT, CT, and HFT	28.9	32.1	Willamette River	OT
Station "L"	Portland	Oregon	1, 2, 3, 4, and 5.	GAOT	75.5	82.0	Willamette River	OT
Station "E"	Portland	Oregon	1 and 2	OT	10.0	9.0	Willamette River	OT
Station "H"	Portland	Oregon	1	OT	2.5	3.0	Willamette River	OT
Lincoln	Portland	Oregon	1, 2, and 3	GAOT and HFT.	35.5	47.0	Willamette River	OT
Astoria	Astoria	Oregon	1 and 2	OT	8.0	7.0	Youngs River	OT
Springfield	Springfield	Oregon	1	HFT	5.0	5.0	Willamette River	OT
North Bend	North Bend	Oregon	1 and 2	OT	15.0	15.0	Coos Bay	OT
Tillamook	Tillamook	Oregon	1, 2, and 3	OT and HFT	6.3	6.5	Trask River	OT
Tillamook	Tillamook	Oregon	1 and 2	D	1.8	1.8		
Longview	Longview	Washington	1, 2, 3, 4, and 5.	GAOT and HFT	26.0	30.0	Columbia Log Pond	OT
Aberdeen	Aberdeen	Washington	1, 2, 3, and 4	GAOT	12.9	12.9	Grays Harbor	OT
Tacoma No. 1	Tacoma	Washington	1 and 2	GAOT	9.0	10.0	Puget Sound	OT
Tacoma No. 2	Tacoma	Washington	1 and 2	GAOT and CT	50.0	55.0	Puget Sound	OT
Lake Union	Seattle	Washington	11, 12, and 13	GAOT	30.0	40.0	Lake Union	OT
Georgetown	Seattle	Washington	1, 2, and 3	GAOT	21.0	21.0	Duwamish River	OT
Shuffleton	Renton	Washington	1 and 2	GAOT	90.0	86.0	Lake Washington	OT
Bonners Ferry	Bonners Ferry	Idaho	1	D	0.2	0.2		
Hanford	Hanford	Washington	1 and 2	N	786	786	Columbia River	OT
Industrial and miscellaneous resources [6]					155.8	81.0		
Total thermal and miscellaneous					1,374.0	1,334.0		

[1] Unit identification.
[2] OT=Oil Fired Thermal, GAOT=Gas or Oil Fired Thermal, N=Nuclear, D=Diesel, CT=Coal Fired Thermal, HFT=Hogged Fuel Thermal.
[3] Net capability of units—excludes station use.
[4] Summation of capability of all units at the time of peak demand.
[5] OT=Once through cooling direct from ocean or river.
[6] Purchased power. Part of the capability of these plants is reserved to owner's use.

TABLE 9–2

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location: Stream	Location: State	Number of units	Type [1]	Capability megawatts [2]
Hydro resources in PSA 42, 43, 44, and 45:					
Columbia mainstem:					
Noxon Rapids	Clark Fork River	Idaho	4	H	419
Cabinet Gorge	Clark Fork River	Idaho	4	H	230
Albeni Falls	Pend Oreille	Idaho	3	H	23
Box Canyon	Pend Oreille	Washington	4	H	79
Boundary	Pend Oreille	Washington	4	H	632
Spokane River	Spokane River	Washington	23	H	149
Grand Coulee	Columbia River	Washington	18	H	2, 276
Chief Joseph	Columbia River	Washington	16	H	1, 280
Wells	Columbia River	Washington	10	H	820
Chelan	Chelan River	Washington	2	H	52
Rocky Reach	Columbia River	Washington	7	H	815
Rock Island	Columbia River	Washington	4	H	158
Wanapum	Columbia River	Washington	10	H	986
Priest Rapids	Columbia River	Washington	10	H	912
Lewiston	Clearwater River	Idaho	2	H	10
Little Goose	Snake River	Washington	3	H	466
Lower Monumental	Snake River	Washington	3	H	466
Ice Harbor	Snake River	Washington	3	H	310
McNary	Columbia River	Oregon-Washington	14	H	1, 127
John Day	Columbia River	Oregon-Washington	14	H	2, 174
Round Butte	Deschutes River	Oregon	3	H	274
Pelton	Deschutes River	Oregon	3	H	124
The Dalles	Columbia River	Oregon-Washington	16	H	1, 286
Bonneville	Columbia River	Oregon-Washington	10	H	558
Total mainstem hydro			190	....	15, 626

[1] H = Hydro.

[2] Summation of capability of all units at time of peak demand.

TABLE 9–3

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location: Stream	Location: State	Number of units	Type [1]	Capability megawatts [2]
Seasonal hydro:					
Carmen	McKenzie River	Oregon	2	H	102
Trail Bridge	McKenzie River	Oregon	1	H	5
Detroit	N. Santiam River	Oregon	2	H	102
Big Cliff	N. Santiam River	Oregon	1	H	5
Lookout Point	M. Fk. Willamette	Oregon	3	H	76
Dexter	M. Fk. Willamette	Oregon	1	H	3
Cougar	S. Fk. McKenzie	Oregon	2	H	
Hills Creek	M. Fk. Willamette	Oregon	2	H	30
Greek Peter	Middle Santiam	Oregon	2	H	71
Foster	South Santiam	Oregon	2	H	6
Oak Grove	Oak Grove Kf	Oregon	2	H	49
North Fork	Clackamas River	Oregon	2	H	54
Faraday	Clackamas River	Oregon	6	H	44
River Mill	Clackamas River	Oregon	5	H	23
Swift No. 1	Lewis River	Washington	3	H	193
Swift No. 2	Lewis River	Washington	2	H	77
Yale	Lewis River	Washington	2	H	120
Merwin	Lewis River	Washington	3	H	146
Klamath River	Klamath River	Oregon	9	H	172
Alder	Nisqually River	Washington	2	H	40
La Grande	Nisqually River	Washington	5	H	65
Cushman No. 1	N. Fk. Skokomish	Washington	2	H	17
Cushman No. 2	N. Fk. Skokomish	Washington	3	H	88
Mayfield	Cowlitz River	Washington	3	H	133
Mossyrock	Cowlitz River	Washington	2	H	239
Ross	Skagit River	Washington	4	H	355
Diablo	Skagit River	Washington	2	H	159
Gorge	Skagit River	Washington	4	H	175
White	White River	Washington	4	H	55
Upper Baker	Baker River	Washington	2	H	89
Lower Baker	Baker River	Washington	3	H	105
Total Seasonal Hydro			86	....	2, 798

[1] H=Hydro.

[2] Summation of capability of all units at time of peak demand.

TABLE 9–4

Generation Resources for West Region as of 1970 (Base Year)

Project name	Location stream	State	Number of units	Type [1]	Capability megawatts [2]
Pondage and Minor Hydro:					
Walterville	McKenzie River	Oregon	1	H–HPS	9
Leaburg	McKenzie River	Oregon	2	H	12
Chandler	Yakima River	Washington	2	H	12
Roza (Net)	Yakima River	Washington	1	H	11
Bull Run and T. W. Sullivan	Sandy River and Willamette River.	Oregon	17	H	34
Umpqua	Umpqua River	Oregon	8	H	204
Condit and Minors	White Salmon River	Oregon-Washington	5	H	25
Rogue	Rogue River	Oregon	9	H	48
Yelm	Nisqually River	Washington	3	H	10
Cedar Falls	Cedar River	Washington	2	H)	29
Newhalem	Newhalem Creek	Washington	1	H)	
Snoqualmie and Minors	Snoqualmie River	Washington	7	H	72
Packwood	Lake Creek	Washington	1	H	30
Total Pondage and Minor Hydro.			59		496
Total Hydro Resources			335		18, 920
Total Hydro and Thermal Resources					20, 254

[1] H = Hydro, H–HPS = Combination Conventional and Pumped Storage Hydro.
[2] Summation of capability of all units at time of peak demand.

TABLE 9–5

Generation Resources for West Region as of 1980 (Additions and Deductions Following 1970)

Project name	Location [1]		Number of units [2]	Type [3]	Capability—mw	
	City	State			Unit(s) [4]	Project [5]
Centralia	Centralia	Washington	1 and 2	CT	1, 400	1, 400
Hanford (NPR)	Hanford	Washington		N	[6] 57	[6] 57
Nuclear		Oregon	1	N	1, 000	1, 000
Nuclear		Washington	1	N	1, 000	1, 000
Nuclear		Washington	1	N	1, 000	1, 000
Nuclear		Oregon	1	N	1, 000	1, 000
Nuclear		Washington	1	N	1, 000	1, 000
Nuclear		Oregon	1	N	1, 000	1, 000
Nuclear		Oregon	1	N	1, 000	1, 000
Total thermal					8, 457	8, 457

[1] Site selection will depend upon economic and environmental factors.
[2] Unit identification.
[3] CT = Coal Fired Thermal, N = Nuclear.
[4] Net capability of units—excludes station use.
[5] Summation of capability of all units at the time of peak demand.
[6] Added capability under single purpose operation.

TABLE 9–6

Generation Resources for West Region as of 1980 (Additions and Deductions Following 1970)

Project name	Location stream	State	Number of units	Type [1]	Capability megawatts [2]
Columbia mainstem:					
Grand Coulee 3rd P.H.	Columbia River	Washington	6	H	3, 338
Grand Coulee P–T's 7 and 8	Columbia River	Washington	2	HPS	85
Grand Coulee P–T's 9 and 10	Columbia River	Washington	2	HPS	85
Chief Joseph Additions	Columbia River	Washington	11	H	880
Rocky Reach Additions	Columbia River	Washington	4	H	451
Lower Monumental	Snake River	Washington	3	H	466
Lower Granite	Snake River	Washington	3	H	466
Dworshak	N. Fk. Clearwater River	Idaho	3	H	423
Asotin	Snake River	Idaho-Washington	2	H	310
China Gardens	Snake River	Idaho-Washington	3	H	207
High Mountain Sheep	Snake River	Idaho-Oregon	3	H	900
Ice Harbor Additions	Snake River	Washington	3	H	310
John Day	Columbia River	Oregon-Washington	2	H	310
The Dalles	Columbia River	Oregon-Washington	8	H	791
Bonneville 2nd and P.H.	Columbia River	Oregon-Washington	6	H	343
Total mainstem hydro			61	....	9, 365
Seasonal hydro:					
Wenatchee River	Wenatchee River	Washington	6	H	150
Sultan	Sultan River	Washington	5	H	140
Muddy Meadows	Lewis River	Washington	3	H	105
Foster	S. Santiam River	Oregon	1	H	12
Lost Creek	Rogue River	Oregon	2	H	34
Eden Ridge	Rogue River	Oregon	1	H	177
Klamath River Additions	Klamath River	Oregon	4	H	118
Mayfield Addition	Cowlitz River	Washington	1	H	44
Total Seasonal Hydro			23	....	680

[1] H = Hydro, HPS = Pumped Storage Plant.

[2] Summation of capability of all units at time of peak demand.

TABLE 9–7

Generation Resources for West Region as of 1980 (Additions and Deductions Following 1970)

Project name	Location stream	State	Number of units	Type [1]	Capability megawatts [2]
Pondage and minor hydro:					
Total pondage and minor hydro			0	....	0
Total hydro resources			84	....	10, 045
Total hydro and thermal resources			93	....	18, 502

[1] H = Hydro, HPS = Pumped Storage Plant.

[2] Summation of capability of all units at time of peak demand.

TABLE 9–8

Generation Resources for West Region as of 1990 (Additions and Deductions Following 1980)

Project name	Location[1] City	Location[1] State	Number of units[2]	Type[3]	Capability—mw Unit(s)[4]	Capability—mw Project[5]
Nuclear		Washington	1	N	1,000	1,000
Nuclear		Washington	1	N	1,000	1,000
Nuclear		Oregon	1	N	1,000	1,000
Nuclear		Washington	1	N	1,000	1,000
Nuclear		Oregon	1	N	1,000	1,000
Nuclear		Washington	1	N	1,000	1,000
Nuclear		Oregon	1	N	1,000	1,000
Nuclear		Washington	1	N	1,000	1,000
Nuclear		Oregon	1	N	1,000	1,000
Nuclear		Washington	1	N	1,000	1,000
Nuclear		Oregon	1	N	1,000	1,000
Nuclear		Oregon	1	N	1,000	1,000
Nuclear		Washington	1	N	1,000	1,000
Nuclear		Washington	1	N	1,000	1,000
Nuclear		Oregon	1	N	1,000	1,000
Nuclear		Washington	1	N	1,000	1,000
Nuclear		Oregon	1	N	1,000	1,000
Nuclear		Oregon	1	N	1,000	1,000
Nuclear		Washington	1	N	1,000	1,000
Total thermal peak resources			19		19,000	19,000

[1] Site selection will depend upon economic and environmental factors.
[2] Unit identification.
[3] N = Nuclear.
[4] Net capability of units—Excludes station use.
[5] Summation of capability of all units at the time of peak demand.

TABLE 9–9

Generation Resources for West Region as of 1990 (Additions and Deductions Following 1980)

Project name	Location: Stream	Location: State	Number of units	Type [1]	Capability megawatts [2]
Hydro resources in PSA 42, 43, 44, and 45:					
Columbia mainstem:					
Katka	Kootenai River	Idaho	5	H	250
Sullivan Creek	Sullivan Creek	Washington	2	H	14
Boundary Additions	Pend Oreille River	Washington	2	H	316
Grand Coulee 3rd P.H.	Columbia River	Washington	6	H	3, 320
Grand Coulee P–T's 11 and 12	Columbia River	Washington	2	HPS	85
Chief Joseph Additions	Columbia River	Washington	4	H	320
Chelan Additions	Chelan River	Washington	3	H	72
Rock Island Additions	Columbia River	Washington	7	H	265
Wanapum Additions	Columbia River	Washington	6	H	499
Priest Rapids Additions	Columbia River	Washington	6	H	473
High Mountain Sheep	Snake River	Idaho-Oregon	2	H	600
Wenaha	Grand Ronde River	Washington	3	H	201
Asotin	Snake River	Idaho-Washington	2	H	310
Penny Cliffs	M. Fk. Clearwater River.	Idaho	6	H	420
Dworshak Additions	N. Fk. Clearwater River	Idaho	3	H	660
Lenore	Clearwater River	Idaho	4	H	230
Lower Granite	Snake River	Washington	3	H	466
Little Goose Additions	Snake River	Washington	3	H	466
Ben Franklin	Columbia River	Washington	10	H	400
John Day	Columbia River	Oregon-Washington	4	H	621
Total mainstem hydro			83	....	9, 988

[1] H = Hydro, HPS = Pumped Storage Plant.

[2] Summation of capability of all units at time of peak demand.

TABLE 9–10

Generation Resources for West Region as of 1990 (Additions and Deductions Following 1980)

Project name	Location: Stream	Location: State	Number of units	Type [1]	Capability megawatts [2]
Seasonal hydro:					
Klamath River Additions	Klamath River	Oregon		H	164
Buzzards Roost	Illinois River	Oregon	2	H	120
Coogar Additions	South Fork McKenzie River.	Oregon	1	H	35
Strube	South Fork McKenzie River.	Oregon	1	H	5
Merrill Lake Pumped Storage	Merrill Lake	Washington	2	HPS	500
Yale Additions	Lewis River	Washington	2	H	133
Merwin Additions	Lewis River	Washington	1	H	50
Mossyrock Additions	Cowlitz River	Washington	1	H	99
Wenatchee River	Wenatchee River	Washington		H	150
Total seasonal hydro			10		1, 256
Pondage and minor hydro:					
North Fork Snoqualmie	North Fork Snoqualmie River.	Washington	3		60
Total pondage and minor hydro			3		60
Total hydro resources			96		11, 304
Total hydro and thermal resources			115		30, 304

[1] H = Hydro, HPS = Pumped Storage Plant.
[2] Summation of capability of all units at time of peak demand.

TABLE 10

Area P Resources Summary

[Megawatts]

	1970	1980	1990
I Peak demand (MW) [1]:			
PSA 42	2, 190	2, 950	3, 750
PSA 43	5, 760	11, 780	22, 580
PSA 44 and 45	8, 930	17, 400	32, 900
Total	16, 880	32, 130	59, 230
II Capacity resources (MW):			
Hydro: [2]			
Conventional	18, 920	28, 795	39, 514
Pumped storage	0	170	755
Total	18, 920	28, 965	40, 269
Thermal:			
Gas and Oil	548	[3] 548	[3] 548
Coal	0	1, 400	1, 400
Nuclear	786	7, 843	26, 843
Gas Turbines	0	0	0
Total	1, 334	9, 791	28, 791
Purchase from others	297	0	0
Sales to others	(2, 167)	(3, 456)	(3, 926)
Total resources	18, 384	35, 300	65, 134
III Gross margin—Capacity resource in excess of peak demand	1, 504	3, 170	5, 904
IV Maintenance at time of peak	0	0	0
V Net margin at time of peak	1, 504	3, 170	5, 904
Percent of peak demand	8. 9	9. 9	10. 0

[1] FPC load forecast of February 1968.
[2] Capacity for month of peak demand assuming adverse hydro conditions.
[3] Assumes replacement of existing plants.

West Region—Peak Demands by Load Centers

Power supply area	Load center	Peak demand			
		1966 [1]	1970	1980	1990
		Megawatts			
31	Casper	179	249	546	1, 100
	Cheyenne	124	172	378	756
	Scottsbluff	87	121	265	531
	Cody	83	115	253	507
	Unassigned	42	58	128	256
	Total	515	715	1, 570	3, 150
32	Denver	986	1, 360	2, 700	5, 130
	Colorado Springs	306	423	839	1, 590
	Montrose Grand Junction	162	223	444	842
	Poncha	77	106	211	400
	Unassigned	13	18	36	68
	Total	1, 544	2, 130	4, 230	8, 030
36	Amarillo	473	632	1, 230	2, 250
	Lubbock	512	685	1, 330	2, 440
	Hobbs	291	389	756	1, 390
	Unassigned	63	84	164	300
	Total	1, 339	1, 790	3, 480	6, 380
39	Albuquerque	363	496	1, 040	1, 960
	El Paso	394	539	1, 140	2, 130
	Unassigned				
	Total	757	1, 035	2, 180	4, 090
40	Butte-Anaconda	551	700	1, 240	2, 260
	Billings	138	175	312	563
	Helena-Great Falls	260	330	587	1, 060
	Kalispell-Missoula	173	220	390	707
	Unassigned	27	35	61	110
	Total	1, 149	1, 460	2, 590	4, 700
41	Boise	439	540	1, 080	2, 190
	Pocatello	1, 018	1, 250	2, 510	5, 050
	Salt Lake City	712	880	1, 760	3, 540
	Cedar City	70	86	172	350
	Unassigned	68	84	168	340
	Total	2, 307	2, 840	5, 690	11, 460
42	Spokane	[1] 1, 388	1, 740	2, 340	2, 980
	Coeur d'Alene	178	220	300	380
	Lewiston	183	230	310	390
	Unassigned				
	Total	1, 749	2, 190	2, 950	3, 750

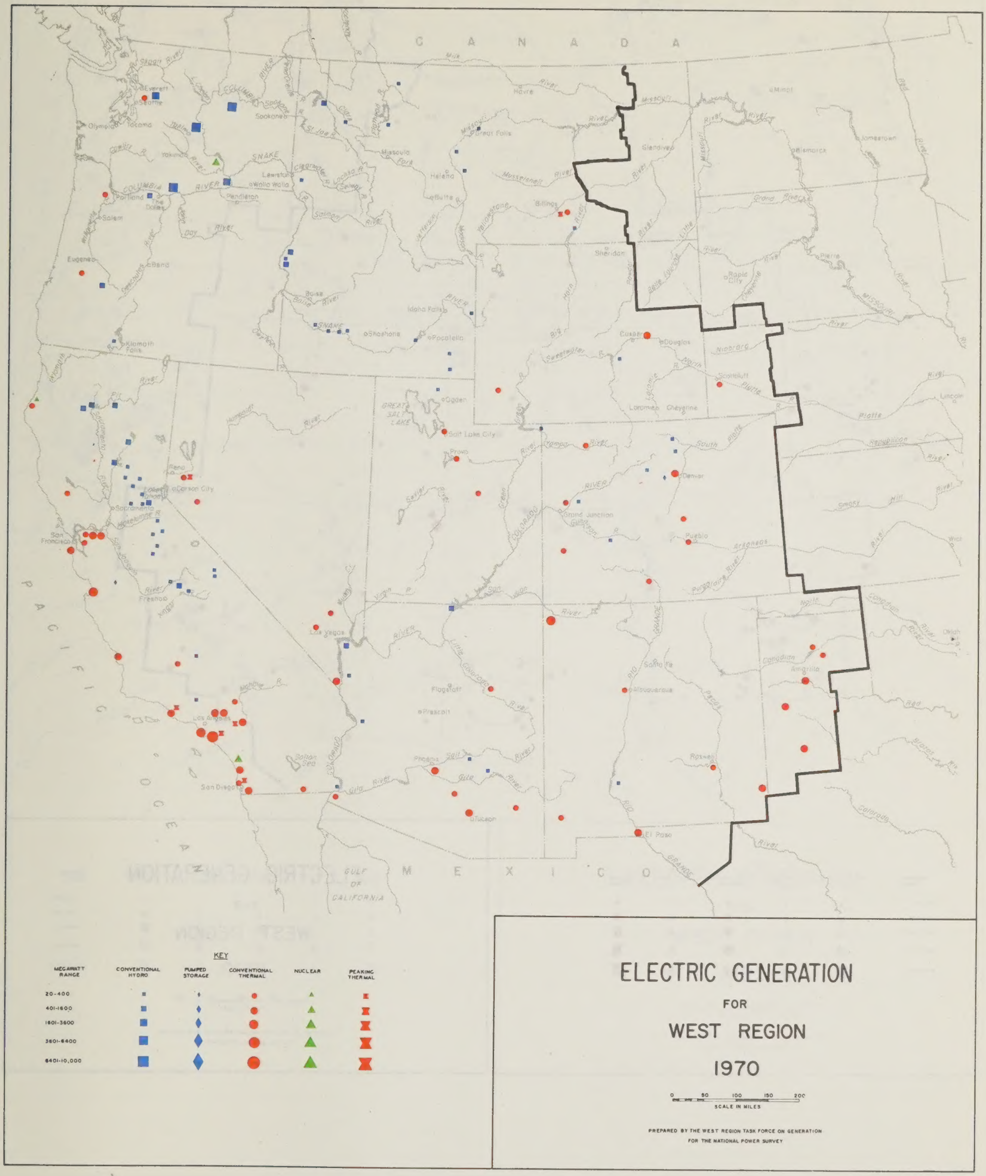
See footnote at end of table.

West Region—Peak Demands by Load Centers—Continued

Power supply area	Load center	Peak demand 1966 [1]	1970	1980	1990
		Megawatts			
43	Seattle-Tacoma	2, 557	3, 440	7, 040	13, 500
	Bellingham	287	386	789	1, 520
	Olympia	330	444	907	1, 740
	Chelan	1, 037	1, 400	2, 860	5, 470
	Unassigned	67	90	184	350
	Total	4, 278	5, 760	11, 780	22, 580
44–45	Portland	3, 455	5, 350	10, 400	19, 700
	Eugene	940	1, 450	2, 840	5, 360
	Roseburg-Medford	857	1, 330	2, 590	4, 880
	Pasco	406	625	1, 230	2, 310
	Unassigned	114	175	340	650
	Total	5, 772	8, 930	17, 400	32, 900
46	San Francisco	3, 764	5, 060	10, 900	23, 300
	Sacramento	1, 764	2, 370	5, 090	10, 900
	Fresno	1, 463	1, 970	4, 230	9, 060
	Reno	238	320	690	1, 480
	Red Bluff	608	815	1, 760	3, 780
	Unassigned	495	665	1, 430	3, 080
	Total	8, 332	11, 200	24, 100	51, 600
47	Los Angeles	6, 821	9, 150	19, 100	37, 800
	San Diego	904	1, 210	2, 520	5, 020
	San Bernardino	1, 295	1, 740	3, 600	7, 200
	Ventura	397	530	1, 100	2, 200
	Tulare	272	365	750	1, 510
	Brawley	115	155	320	640
	Unassigned	113	150	310	630
	Total	9, 917	13, 300	27, 700	55, 000
48	Phoenix	1, 450	2, 000	4, 260	9, 180
	Tucson	484	668	1, 420	3, 060
	Yuma	658	908	1, 940	4, 160
	Las Vegas	499	688	1, 470	3, 160
	Unassigned	164	226	480	1, 040
	Total	3, 255	4, 490	9, 570	20, 600

[1] Approximate.

APPENDIX 3—2 ELECTRIC GENERATION MAPS



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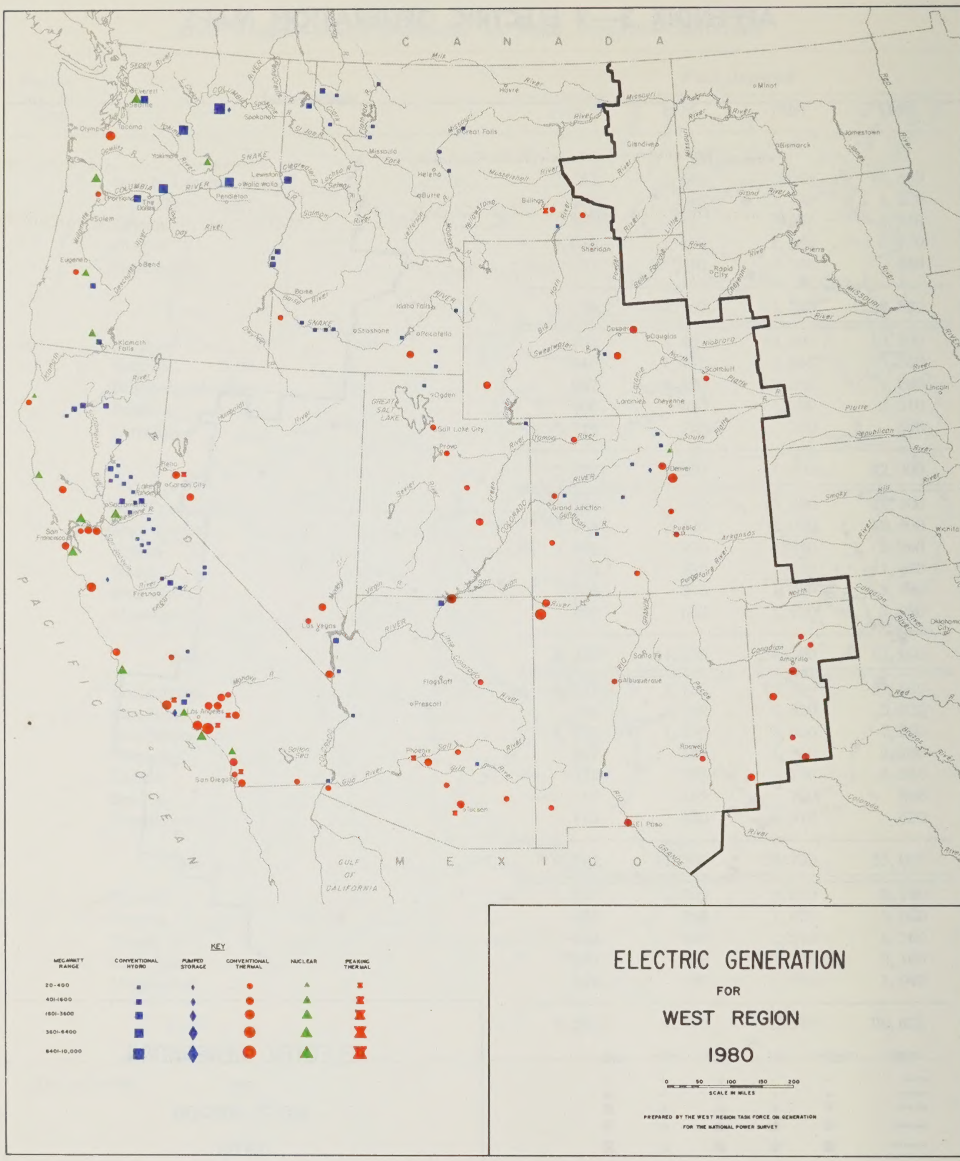
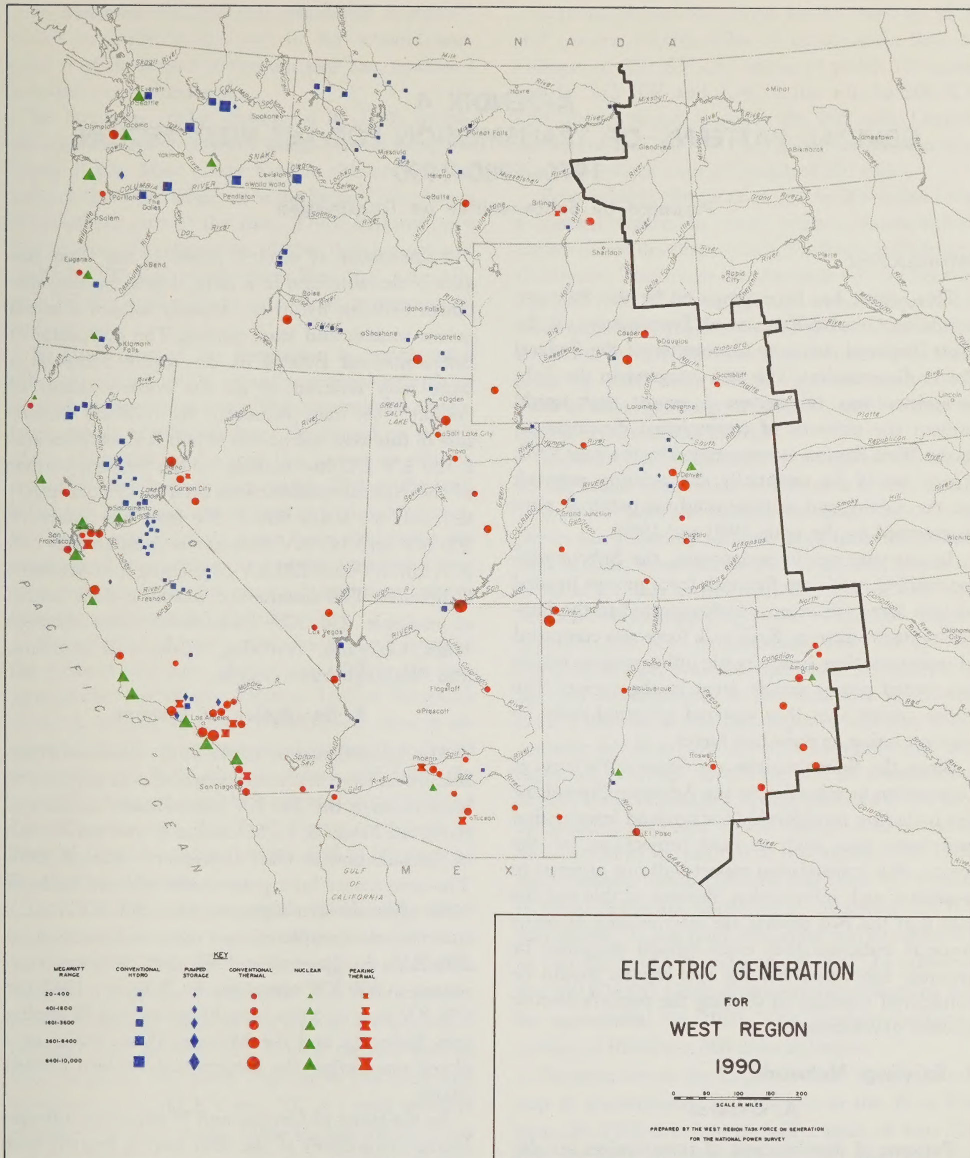


ELECTRIC GENERATION
FOR
WEST REGION
1980
SCALE IN MILES
PREPARED BY THE WEST REGION TASK FORCE ON GENERATION FOR THE NATIONAL POWER SURVEY
KEY
MEGAWATT RANGE
CONVENTIONAL HYDRO
PUMPED STORAGE
CONVENTIONAL THERMAL
NUCLEAR
PEAKING THERMAL
20-400
401-1600
1601-3600
3601-6400
6401-10,000
CANADA
PACIFIC OCEAN
MEXICO
GULF OF CALIFORNIA



ELECTRIC GENERATION
FOR
WEST REGION
1990
0 50 100 150 200
SCALE IN MILES
PREPARED BY THE WEST REGION TASK FORCE ON GENERATION
FOR THE NATIONAL POWER SURVEY
KEY
MEGAWATT RANGE
CONVENTIONAL HYDRO
PUMPED STORAGE
CONVENTIONAL THERMAL
NUCLEAR
PEAKING THERMAL
20-400
401-1600
1601-3600
3601-6400
6401-10,000
C A N A D A
M E X I C O
P A C I F I C O C E A N
GULF OF CALIFORNIA
GREAT SALT LAKE

APPENDIX 4
GENERAL PATTERNS OF TRANSMISSION FOR THE WEST REGION, 1970–1980–1990

Prepared by Subcommittee on Transmission

Introduction

This report has been prepared by the Subcommittee on General Patterns of Transmission of the West Regional Advisory Committee of the Federal Power Commission. The task assigned to the Subcommittee was to prepare a report that would present the patterns of transmission development in the West Region as represented by the year 1970, which would be essentially the existing network for the region, and as forecasted for points in time represented by the years 1980 and 1990.

In carrying out its assignment, the Subcommittee divided itself into five task force groups headed by task force chairmen which reported to the Subcommittee chairman. Each task force was composed of representatives from electric utility systems within designated power supply areas in the region. The entire region was thus covered geographically by representation on these task forces.

Since the Subcommittee on General Patterns of Generation in reporting to the Advisory Committee are including considerable background information and basic data such as load projections for the region, this transmission report will not attempt to duplicate such information. Because of this and the fact that the two reports are inter-related in many respects indicates that even though prepared by separate subcommittees the two reports should be considered together in viewing the region's electric systems development.

I. Existing Network

A. General

Patterns of development of transmission are determined by types and locations of sources of power supply, including interconnections, in relation to characteristics and locations of loads served. As a result of the inter-relationship of these factors, transmission systems in Western United States have developed as represented on the maps included herewith on which are shown major transmission lines as of 1970.

Transmission of electric power in the West Region is characterized to a large degree by long distances between hydro or remotely located thermal power sources and load centers. The composite of interconnected systems in the region comprise a large loop referred to as the Western Loop or "donut" (see map included). By 1970 the western side of this loop will consist of 500 KV AC lines and a 750 KV DC line making up the western portion of the Northwest-Southwest intertie (Pacific intertie) and the south side of the loop will consist of 500 KV and 345 KV lines across Arizona with 500 KV, 287 KV and 230 KV continuing into Southern California. The eastern and northern sides consist of multiple 230 KV transmission lines through Utah, Colorado, Wyoming, Idaho and Montana into Washington and Oregon.

B. Description of Systems

The transmission networks in the Northwest and Southwest were first interconnected on a permanent basis through the 230 KV transmission facilities of the Utah Power & Light Company and the Bureau of Reclamation at Glen Canyon in October 1964. The next major inter-connection occurred in April 1966 when the first segment of the 500 KV Pacific intertie was completed and operated initially at 230 KV. In November 1967 that line was converted to 500 KV operation. In February 1967 the 230 KV east-west ties from Montana and Wyoming into Nebraska and the Missouri River Basin were closed connecting the eastern and western United States.

In the states of Oregon and Washington approximately two-thirds of the area load is located west of the Cascade mountains. Generation supplying this load, however, is essentially all hydro, 80% of which is located east of the Cascades with heavy concentration of generation in the mid-Columbia and lower Snake River areas. During winter peak load conditions a heavy westward flow of power occurs necessitating a substantial network of east-west transmission lines.

In Montana the load and generation is concentrated in south central and in the western one-quarter of the state and transmission has developed to interconnect these areas.

In Southern Idaho generation is 100% hydroelectric with the majority of plants located along the Snake River. Most of the load in this area is also located along and adjacent to the Snake River across the southern part of the state. These features have determined the character of the development of multiple 230 KV transmission lines that generally parallel the Snake River to connect generation to load centers.

In Utah most of the generation is conventional thermal electric with recently constructed plants located at the coal source. The transmission system from power plants has been developed to match plant capacities and carry the power to North-central Utah where approximately 80% of the load is located. Interconnecting lines to Idaho, Montana, Wyoming and Arizona have been developed for purposes of firm and reserve power transfers, economy and surplus hydro energy interchange, power wheeling and seasonal diversity.

The relation of load centers to power sources in the Arizona and New Mexico areas follow the pattern of the rest of the Western United States. A network of long distance transmission lines is required to transmit power to load centers from hydro generation on the Colorado River and from the thermal power plant at the large coal deposits in the Four Corners area. The load centers served are in New Mexico, Southern Arizona and as far away as Southern California.

As a result of the geographic relationship of remote sources of power supply and major load centers in the West Region, the average transmission distance is in excess of 150 miles. This characteristic, coupled with advances in the state of the art, rapid regional load growth and limited right-of-way in some localities has given impetus to planning and construction of 345 KV and 500 KV grid overlays of basic 230 KV systems. These higher voltage grids are now developing to provide the principal integration of generation with major load centers. The first two transmission lines in the West Region to operate at 500 KV were energized at that voltage in 1967. One of these lines interconnected the Hanford nuclear plant and the Seattle area in the Northwest and the other comprised a northern section of the Pacific intertie.

Systems of the Northwest Power Pool by 1970 will operate 16,600 miles of transmission lines at voltages of 230 KV and above of which 710 miles will be 345 KV and 1,540 miles will be 500 KV and above, which includes the 265 mile Oregon portion of the 750 KV DC Celilo-Sylmar transmission line with an over-all length of 851 miles.

Transmission distances of 150 to 200 miles from mountain hydro to load centers characterized earlier power developments in Northern and Central California. The major transmission voltage became 230 KV (220 KV initially) and served this area for more than forty years until 500 KV was introduced as part of the Pacific intertie development. In these areas by 1970 there will be approximately 1,165 miles of lines operating at 500 KV, and in excess of 5,000 circuit miles at 230 KV.

Southern California load centers are concentrated on the coast. Generation in this area is only about 10% hydro with the balance thermal. The thermal plants are generally located in or near the coastal load centers, however, by 1970 coal-fired plants located as far east as the Four Corners area of New Mexico will be supplying power to the Los Angeles area on 500 KV transmission lines. Except for pumped storage, available hydro sites are approaching full development in the Southern California area. This means that hydro power will play a decreasing role in providing future energy supply. It is expected, however, that there will be a continuing development of pumped storage facilities in the area for peaking purposes. These changes will naturally be reflected in the pattern of transmission. By 1970, the Southern California area will have 4,474 miles of transmission line operating at voltages of 230 KV and above. Of this total, 446 miles will be operating at 500 KV and 790 miles at 287 KV. In addition, the 750 KV DC Celilo-Sylmar transmission line will be operational by 1970. The Nevada-California portion of this line is 586 miles in length.

Construction of the Pacific intertie is a significant step in transmission development in the West Region. By 1970 this intertie will consist of two 500 KV AC lines and one 750 KV DC line. The two 500 KV lines of the intertie supplement the backbone transmission in California. Use of 500 KV is also planned for integration of thermal plants with load centers in Arizona. The principal network voltage on the east side of the interconnected systems in the region will continue to be 230 KV at least through 1970.

When completed the Pacific intertie will interconnect the northern and southern sections of the West Region each with different types of generation and load patterns and will thus provide the vehicle for several types of peak and energy transfers with resulting benefits to each section of the region.

C. System Operations and Characteristics

1. *General.*—The West Region is composed of a number of operating areas which have achieved a high degree of reliable operation. Procedures in these areas for meeting operating contingencies vary. Under extreme conditions, both load shedding and opening of interconnections are used to avoid extensive and prolonged disruption of service. Determination of requirements for load shedding varies from line loading and line tripping to under-frequency relay operation and operator decisions. Interruptions of interconnections vary from automatic relaying under selected conditions to tripping only at such time as there is danger of damage to connected equipment. Studies are proceeding under the direction of the Western Systems Coordinating Council to continue coordination of these various concepts and operating practices and to establish criteria essential to reliable operation of the region's interconnected systems.

2. *Northwest.*—Generation in the Northwest is, and will continue to be for some time in the future, predominantly hydro characterized by surplus energy and light loads during the spring and summer months in contrast with the Southwest which is dependent for the most part upon thermal generation with heavy summer loads in some areas. In the Northwest during summer load conditions when reservoirs in the eastern part of the system are filling or holding, heavy power flows occur from the Columbia River plants toward the east. During winter load conditions, however, heavy westward power flows occur from the Columbia River plants towards the coastal area. It follows, therefore, that system additions to the western portion of the Northwest area are dictated primarily by winter load conditions while those in the eastern portion are affected primarily by summer load conditions.

3. *Northern Idaho–Montana.*—From Grand Coulee across Northern Idaho and into Western Montana the predominant direction of power flow is toward the east. These flows are heaviest during summer because of reservoir filling and holding as explained above.

4. *Utah, Colorado, Wyoming, Eastern Montana.*—In this area load is served predominantly by thermal plants located relatively near load centers. Tie line transfers over long distances are predominantly seasonal and for economy purposes. Also, scattered throughout the area are a number of moderately sized hydro plants which supply power to remotely located centers of load. Interconnected systems through these states make up the eastern side of the Western Loop.

5. *Southern Idaho.*—This area has a summer peak load resulting from irrigation pumping with heaviest transmission loadings occurring at that time. Power sources to carry the summer load are predominantly along the Snake River. These sources are heavily supplemented from Northwest hydro and to an increasing extent from Wyoming thermal plants. The predominant direction of power flow during both summer and winter is toward the Southeast; however, power flow to the Northwest occurs during the winter.

6. *Northern and Central California.*—In Northern and Central California major load concentrations are in the San Francisco Bay area, and in the Central Valley of the San Joaquin and Sacramento Rivers. While hydro generation, located along the numerous rivers descending into the Central Valley from the Sierra Nevada and southern Cascade mountain ranges has been in the past the major power source, more recently thermal generation has become dominant. Most of the thermal plants are located on tidewater, principally on San Francisco Bay, Monterey Bay and Morro Bay. During the spring and early summer heavy hydro production, especially in favorable precipitation years, results in a power flow from the hydro sources into the Central Valley and the San Francisco Bay areas. As the run-off dwindles the hydro resources serve mostly for peaking and base load is carried by the thermal plants. The ebb and flow of power from the mountain hydro sources and from the coastal stream plants supplies an area load having nearly equal winter and summer peaks, but with a geographical shift of load from summer irrigation and air conditioning in the Central Valley area to winter heating and lighting in the San Francisco Bay area.

7. *Southern California.*—The Southern California load pattern is characterized by a concentration of load in the coastal region and very little load in the interior. As a whole, the area is winter peaking,

but only by a relatively small amount above the summer load. The small portion of the load in the interior tends to be summer peaking.

Most of the energy in Southern California is produced in the general load area by thermal plants. However, some power flows from the large hydro and thermal plants at Hoover Dam and Four Corners.

8. *Southwest.*—The major load centers in the Southwest are located in the population centers of South Central Arizona, Southern Arizona and North Central New Mexico. Generation is located at hydro plants along the Colorado River, large conventional thermal plants located near the vast coal reserves of the Four Corners area, and thermal plants near load centers. There are substantial power flows from the hydro plant at Glen Canyon and the thermal plant at Four Corners to the Phoenix and Tucson load areas to the south.

In addition to large power flow from north to south, the area is characterized by long distances between load and generation sources and an extremely high summer peak due to the heavy pumping and air conditioning load.

9. *Western Loop.*—From the foregoing descriptions of the systems comprising the network of the West Region and from the transmission maps included herewith, a difference in transmission capacity is evident between transmission lines making up the interconnected systems in the eastern side of the Western Loop as compared to those on the balance of the loop. Because of the higher load and generation densities on the latter, higher transmission capacities and resulting use of higher transmission voltages are developing therein. This trend is expected to continue. As indicated earlier in this report, in the area making up the eastern side, load is served predominantly by thermal plants located relatively near load centers and tie line transfers are predominantly seasonal and for economy purposes. Some operating problems within the Loop have been related to disparities in factors such as generating unit size, transmission capacity and relative loading of transmission among the various segments of the Loop. This does not mean that such problems are related to smallness of capacity in one part of the network any more than they are related to largeness of capacity in other parts of the network. A disturbance such as the loss of a large unit or line in the higher capacity area may be well within that area's capability of handling such a disturbance but when reflected into lower capacity segments of the network can result in unacceptable performance. Also, when it has been necessary or expedient to schedule much heavier loadings (relative to capacity) in some parts of the network than in others troublesome power flows have appeared on lines other than where the power flows were scheduled. Study and resolution of system operating problems associated with the above mentioned disparities will continue to be given high priority by members of the Western Systems Coordinating Council.

The 500 KV lines of the Pacific intertie from the Northwest into Southern California were completed in 1968 and one line is scheduled to be extended into Arizona in April, 1969. Studies by the utilities in the area have shown that beginning at that time a substantial "circulating power flow" will begin on the Western Loop due to large exports to the east from the mid-Columbia plants in Washington, flowing counterclockwise around the Loop rather than over the heavily loaded lines east of the mid-Columbia. This condition will be relieved in 1972 by transmission capacity increases east of the mid-Columbia including series capacitor additions, the 500 KV Lower Monumental-Dworshak Dam (near Lolo)-Hot Springs lines and addition of two steam generating units in Wyoming.

The years 1969 through 1971 will then be the years for which accommodation of such "circulating power flow" will probably be most critical. The members of the Western Systems Coordinating Council are in the process of determining changes in power scheduling for the 1969 through 1971 period that can substantially reduce this "circulating power flow."

II. Future Network

A. General

Load forecasts for the systems in the West Region show a growth of 55,395 MW from 1970 to 1980, and 106,990 MW from 1980 to 1990. Some of the resources to meet this growth will be provided by hydro peaking installations particularly in the Northwest and Northern California and coal-fired thermal plants in the Southwest and Rocky Mountain areas. Construction of long distance transmission lines is thus expected to continue to be required for the purpose of bulk power supply from the remote hydro and mine-mouth thermal plants to load centers. The major portion of this load growth re-

quirement, however, will be met by thermal plants located nearer to load centers. In instances where generation will supply separate load areas located relatively close together, large capacity tie lines between the load areas will be economically justified. Future transmission plans for some areas is of necessity based on locating major thermal plants in or adjacent to load centers, thus reducing the requirement for transmission. These are the areas where nuclear plants are expected to develop. With time, the function of the major transmission systems in these areas will change from that of bulk transmission to providing tie line capacity and peaking service. Included herewith are maps showing major transmission lines as they are forecasted to develop for the years 1980 and 1990, respectively.

Future development of Extra High Voltage transmission (EHV) in the West Region will basically be to overlay or parallel existing networks, retaining the transmission loop routed around Nevada. The loop will, however, be considerably strengthened with additional EHV lines. This together with application of advancements in control techniques will result in continuing improvement in the stability and reliability of the interconnected systems.

In this report, development of future transmission is essentially based on the forecasted need and location of generating sources with respect to loads without consideration of possible bulk power transfers outside the West Region resulting from diversity. The transmission systems represented for the years 1980 and 1990 will have adequate capacity for seasonal diversity transfers within the region, but no determination has been made of outside diversities or the ability of the systems to accommodate such diversity exchanges, if any. Future transmission lines and the voltage levels for these years were selected to meet the following conditions:

(*a*) Transmission to load centers of hydro peaking and mine-mouth fossil-fired fuel plant generation.

(*b*) Adequate interconnection capacity to provide necessary emergency service between areas and to provide for interchange of capacity and energy between areas within the region.

It is expected that in the future the 500 KV systems will be strengthened in the Northwest, in Southern California and from the Four Corners—Southern Utah area to Southern California. In the Northwest the principal extension of 500 KV is expected to be into Western Montana. In Idaho, Montana and Utah, multiple 345 KV transmission lines will be built to meet needs of these areas. Transmission at 230 KV is anticipated to be adequate to meet the needs of Wyoming and Colorado during the 1970's with the longer range possibility of going directly from 230 KV to 500 KV in these areas. New Mexico and Western Texas requirements are to be met by expansion at 345 KV.

It can be expected that prior to 1990 transmission lines with AC voltages above 500 KV will find application in the West Region. In this regard, even though the transmission maps included herewith do not indicate transmission lines developing above 500 KV in certain areas, it is recognized such higher voltages may actually be utilized rather than the multiple lower voltage circuits indicated.

B. Description of Systems

1. *Northwest.*—The transmission system in the Northwest area of the region (Washington and Oregon) after 1970 will be reinforced to permit delivery of additional hydro peaking capacity from eastern Oregon and Washington to the major load centers along the coast. It is anticipated that base load increases will be met by nuclear generation located nearer to load centers. For the major transmission additions from the hydro generating areas, plans call for use of voltages above 500 KV to limit the total number of lines crossing the Cascade mountains to the main Portland and Seattle load centers. These lines may be operated at 500 KV to reinforce the planned 500 KV system until about 1980 and will be converted to their higher design voltage as additional transmission capacity is required.

Beginning in the 1970's when most of the feasible hydro sites for production of firm energy will have been developed, the Northwest will embark on a thermal program leading to extensive additions of large (in the order of 1000–1500 MW) base-load thermal units supplemented by hydro peaking. The report of the Task Force on Generation for the West Region indicates a need in the Northwest for about 8,000 MW of new thermal by 1980 and about 27,000 MW by 1990. The preponderance of these thermal plants, primarily nuclear, will be located in the coastal area. Most of the added hydro capacity will be in the form of new peaking-type plants and additions at existing dams primarily on the Columbia River system. It is estimated that the develop-

ment of remaining potential hydro capacity could add nearly an additional 21,000 MW of peaking capacity by 1990.

2. *Montana, Utah, and Idaho.*—EHV development in the Montana, Idaho, and Utah areas will be at the 345 KV level. This voltage is selected because it more economically fits the forecasted needs of this locality than a higher voltage such as 500 KV. The reasons for this are: (1) Some of the existing 230 KV lines in this area are constructed so that they can be economically converted to 345 KV, i.e. bundled conductor is used, conductor spacing is adequate and corner structures have the required strength. Thus, investment required to convert to 345 KV is substantially less than 500 KV construction. (2) The rate of growth is not anticipated to justify building at a higher voltage with a resulting substantial capacity investment being made in advance of need—345 KV more nearly meets the economics of capacity investment increments than a higher voltage. (3) Certain construction and operating advantages can be realized with 345 KV in comparison with a higher voltage. Use can still be made of wood pole structures at this voltage and comparative right-of-way costs are of lesser significance than they might be in other areas. Also, greater network reliability results from multiple 345 KV lines as compared to a single 500 KV line.

3. *Colorado and Wyoming.*—In Colorado and Wyoming continued use of 230 KV transmission is indicated through 1980 with an overlay of 500 KV lines by 1990. The forecasted amount of annual load growth in each area, the economic rate for bringing in new generation and its location is expected to determine the choice of these voltages.

4. *Northern and Central California.*—During the decade 1970–1980 it is estimated that approximately 13,000 MW of thermal capacity and 900 MW of hydro capacity will be added in Northern and Central California. By 1990 an additional 30,000 MW of generating capacity is estimated to be required which will be predominantly thermal, but will include some hydro development mostly for peaking. Bulk transmission of this power is planned to be met by construction of additional 500 KV lines from thermal plants to 500 KV substations in the Central Valley area and reinforcement of the north-south 500 KV lines between the middle and southerly parts of the Central Valley. Extensive additions at 230 KV will be required to tie in the local load centers with the 500 KV bulk power stations. Smaller thermal units (such as the Geysers geothermal plant) and hydro additions will also find outlets over 230 KV lines.

5. *Southern California.*—Future expansion of EHV in the Southern California area will be at 500 KV and largely of an east-west orientation. It will link the Southern California load centers to coal-fired steam plants in the Four Corners and Southern Utah areas or along the Colorado River, strengthen Central to Southern California interconnections, and overlay existing 230 KV systems, thus increasing power transfer capability of the entire network.

Conceivably, voltages above 500 KV may be utilized in order to reduce the number of parallel circuits from the distant coal-fired steam plants. As viewed today, however, expansion is anticipated at 500 KV in order to be compatible with existing ties to the North and with the 1970 transmission from Four Corners. Higher transmission voltages in part of the system would require an additional step of EHV transformation at tie points. Another serious consideration in lumping the transmitted power in fewer parallel circuits is that the capability of the transmission system may be severely taxed in the event of a line outage. This is particularly true if the system is to operate under an n-2 line outage criterion.

6. *Southwest.*—The large coal deposits in Southern Utah, Northern Arizona, and the Four Corners areas will be further developed. Power generated in these areas will flow over a large network of EHV lines to the load centers in Central and Southern Arizona, Southern Utah, Southern California, New Mexico and Western Texas.

As the coal reserves are depleted, it will be necessary to build generating plants near the load centers. At the present time indications are that these could be nuclear plants.

It is expected that peaking capacity will be provided in some areas from conventional hydro installations and/or pumped storage and also from additions of conventional thermal.

C. Interregional Transmission Lines

For the 1970 level of development there are four major 230 KV transmission lines crossing the map boundary between the West Region and the West Central Region. By 1980, six additional lines are shown: Two at 230 KV plus one at 345 KV to the West Central Region and three to the South Central Region at 345 KV. The 1990 level of development indicates that the number of such lines

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may increase to thirteen. Ten of these are with the West Central Region—six 230 KV, three new 500 KV and one 345 KV converted to 500 KV. The three lines shown in 1980 to the South Central Region at 345 KV are all converted to higher voltage by 1990—two to 500 KV and one to 765 KV.

In the forecasted level of transmission development, the amount of interregional tie capacity might be considered to be a part of the natural sequence of transmission growth brought about primarily as a result of growth of adjoining regional networks which includes only an incidental capability of handling interregional power flows. For example all of the lines above 230KV going to the West Central Region are planned primarily for transporting energy easterly from the Montana-Wyoming coal fields.

The extent to which interregional load diversities and other types of power transactions may be substantial enough to justify construction of an interregional high capacity transmission network extending over large areas and long distances can only be determined by a much more exhaustive analysis than any that have been prepared to date. Forecasting the value of diversity far enough into the future on a basis sufficiently firm to be useful in an economic feasibility study presents an extremely complex challenge. If economic advantages do become well-recognized it can be expected that the utility industry will respond as they have in the past under similar circumstances. For example, the Pacific intertie is being built between widely separated areas in the west as a result of cooperative effort on the part of certain public and privately owned utility systems and agencies of the Federal government to take advantage of power transfers and exchanges that are recognized by the parties involved as being capable of realization. The Western Systems Coordinating Council (WSCC) and the recently formed National Electric Reliability Council (NERC) provide additional forums in which the utility industry can continue to improve understandings and concepts that are necessary for further coordinated expansion on an interregional basis of the western power network. An analysis by these groups of the value of interregional diversity is now being proposed which is a step in this direction.

Advancements in transmission technology will have an important impact on interregional transmission. Task Forces within both the Planning Coordination and Operations Committees of WSCC are now studying, with liaison representatives of Mid-Continent Area Power Planners (MAPP) and Southwest Power Pool (SWPP), the unsolved technical problems of electrically joining the eastern Interconnected Systems Group and the Western Loop networks. The concept of bulk power exchanges between regions may become more practical when many of these problems are solved.

In determining the practicality of interregional lines, the degree of advancement that will occur during the years ahead in transmission technology toward reduction in costs per unit of capacity, overcoming the problems of limited right-of-way and meeting public acceptance from the standpoint of appearance in heavily populated terminal areas will be important as will be the establishment of actual interregional power benefits and solutions to the complex contractual, ownership and control problems. Any meaningful evaluations or assumptions that are made in this field must certainly take all of these factors into account.

III. Reliability of Systems

It is believed that the transmission systems represented will have adequate capacity to continue to provide a high degree of reliability. This will be assured by providing capacity needed to match generation to load requirements, by providing adequate levels of interconnecting capacity between areas and also through use of multiple lines and application of improved control techniques. Transmission voltages and numbers of paralleling lines are related to the amount of reserves available both from spinning reserves within load areas and available through interconnections.

In general, it is expected that technological advancements will improve reliability of bulk power transmission system components, including high speed control equipment and techniques.

IV. Load Diversity

In the West Region the major seasonal load diversity will continue to occur between the Northwest having a winter peak, and Arizona having a summer peak. A lesser amount of seasonal load diversity will also continue between the combined Idaho-Utah systems with a summer peak, and neighboring systems in the Northwest and in Montana and Colorado. Future transmission systems will

have sufficient capacity within the region to take advantage of these diversities.

V. Practices in Conserving Rights-of-Way

Planning is being done by systems in the region that will result in upgrading of transmission lines on existing rights-of-way. New transmission tower designs are being developed that will permit the use of right-of-way widths of 125 to 150 feet for a 500 KV circuit. This development will make possible conversion to higher voltages on existing rights-of-way, in some cases without increasing the width. For voltages above 500 KV required minimum conductor spacings make necessary greater width of right-of-way per circuit; however, fewer circuits are required so that total right-of-way is less than if all added lines are at 500 KV. Right-of-way requirements are also related to reliability of transmission since in some instances reliability needs and economics might dictate more transmission circuits at lower voltage rather than fewer circuits at higher voltage or possibly the upgrading of existing lines by installation of series capacitors or reconductoring.

In the Northwest transmission line conversions are planned that will result in upgrading of lines on existing rights-of-way. A double circuit 230 KV transmission line between Chief Joseph Dam and Snohomish, Washington, will be converted to a single circuit 500 KV line by 1971 with an increase in transmission capacity of approximately twice that of the replaced 230 KV circuits. Also, there are plans to replace two 230 KV lines between Midway substation in Central Washington and Bonneville Dam with a line of 500 KV or possibly higher voltage.

In Idaho, Montana and Utah it is planned to upgrade certain transmission lines by raising the voltage from 230 KV to 345 KV. Some lines will be built with provision for future bundling of conductor. There are lines in Southern Idaho and Northern Utah with bundled conductor and operating at 230 KV. These lines can be upgraded for 345 KV operation.

In connecting a new pumped storage hydro plant with a major load center in Colorado, an existing 115 KV line has been replaced with a double circuit 230 KV line. The capability of the right-of-way thus has been increased about eight fold.

In 1970, a 287 KV transmission line extending from the Colorado River area to Los Angeles (237 miles) will be converted to 500 KV with an increase in transmission capacity of about 750 MW. By 1990 two additional 287 KV lines between these locations will be replaced with 500 KV lines.

The foregoing are examples of line replacements and upgrading that indicate what the general practice will be in this regard in the years ahead throughout the West Region.

VI. Appearance of Transmission Lines

There are four principal approaches presently available to reduce the impact of transmission lines on environment. The number of lines can be reduced by increasing line capacity through such means as utilizing higher transmission voltages, series capacitors or reconductoring. Lines can be kept from panoramic views by choice of routing. Architectural improvements can be made in transmission towers. Lines of limited length can be concealed by placing them underground. All of these approaches will be utilized in the future in constructing transmission circuits. However, with the possible exception of increasing transmission voltage, the result in each case will be to increase the cost of transmission capacity. The cost increase for undergrounding of transmission is in most cases prohibitive under present technology.

It is recognized also that factors not now apparent enough to consider in future transmission planning might evolve and materially improve the patterns of transmission development and appearance of lines by 1990. An example is results that might be forthcoming from research now being done on superconductive materials and their possible future application to transmission of electric power.

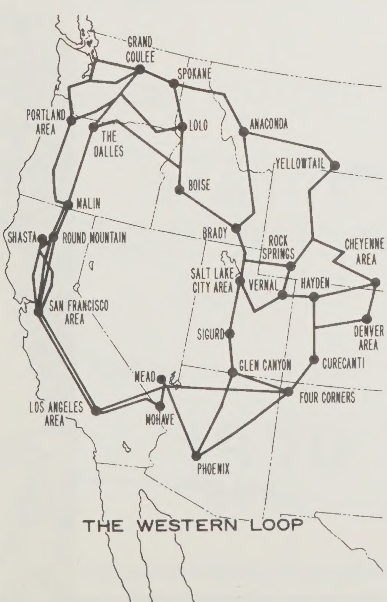
VII. Maps

Two maps of a general nature are included herewith. One is a Federal Power Commission National Power Survey Regions map and the other is a general transmission map of the West Region representing the configuration of lines that comprise the Western Loop.

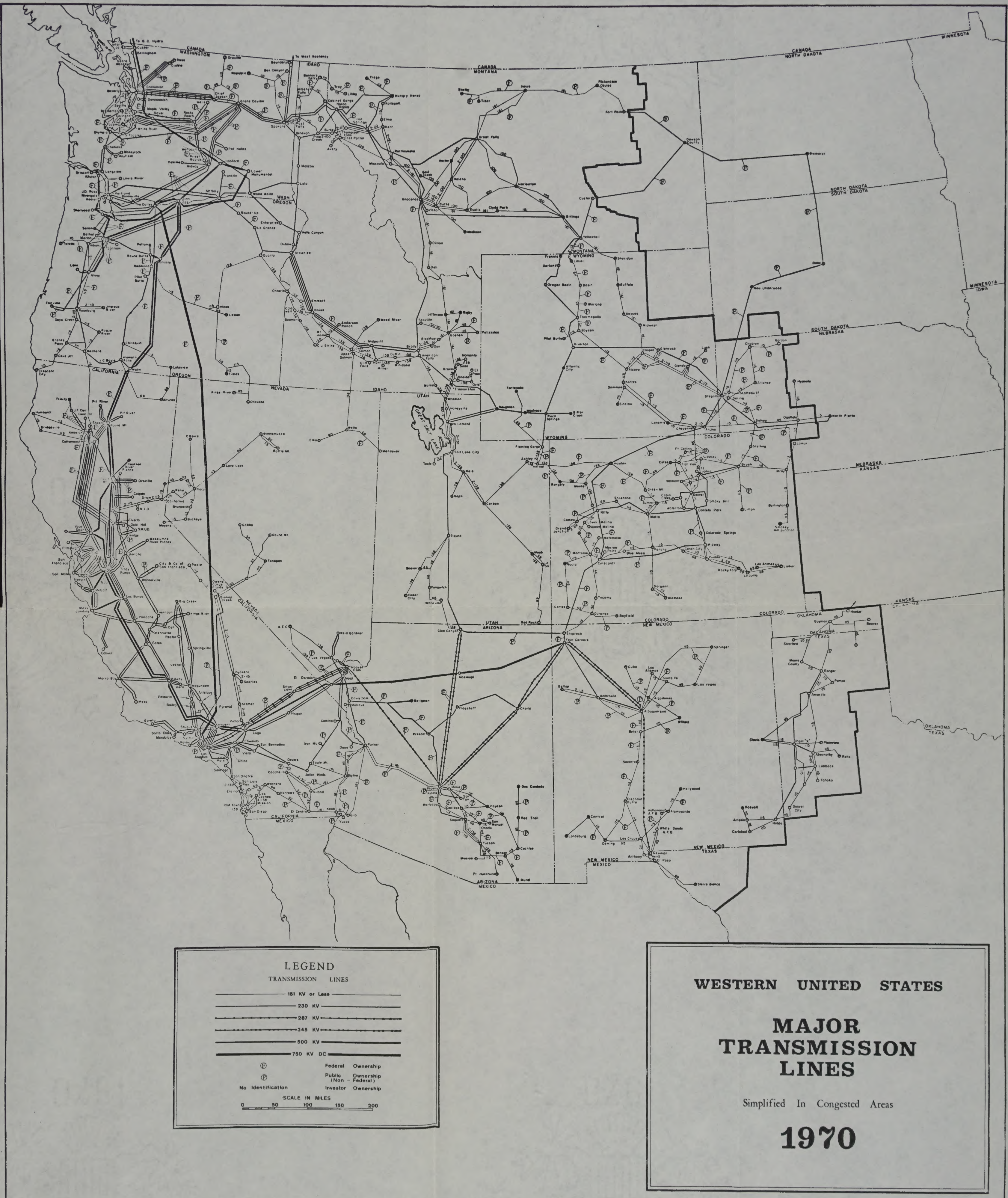
Detailed transmission maps are included representing transmission lines within the West Region for target years 1970, 1980, and 1990. The two 1970 line maps represent essentially the existing systems in the region. One of these maps includes lines with voltages below 230 KV where such lines are significant in providing transmission area cover-

356-240 O - 70 - 31

age and the other shows the same representation except that lines below 230 KV are eliminated. The 1980 and 1990 line maps also delete all lines below 230 KV to provide a clearer visual definition of future transmission development. The line maps for 1980 and 1990 do not attempt to show transmission line detail within certain circumscribed areas where it is believed inadvisable to attempt to give an impression that future lines would occupy specific locations.



THE WESTERN LOOP

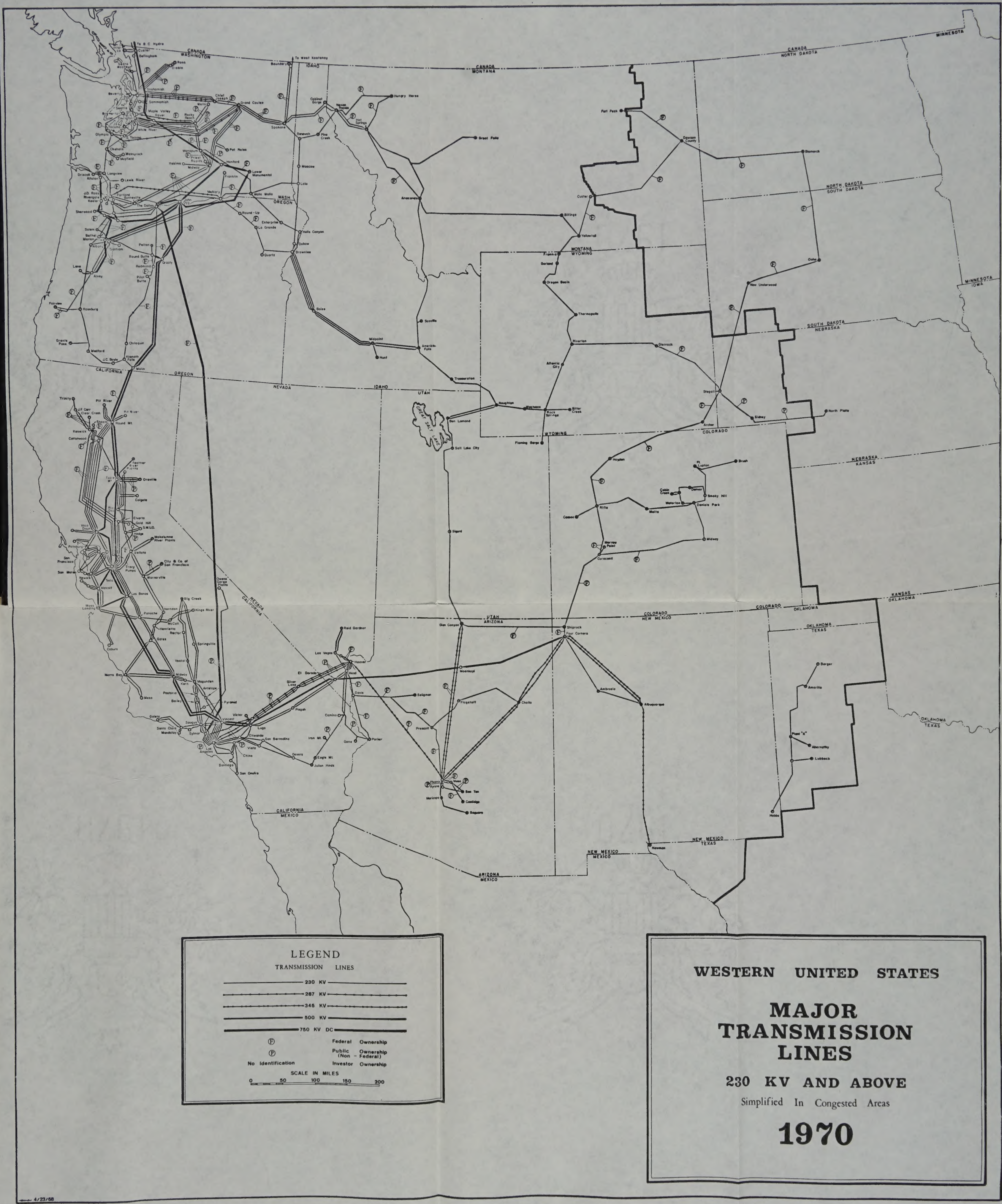


WESTERN UNITED STATES

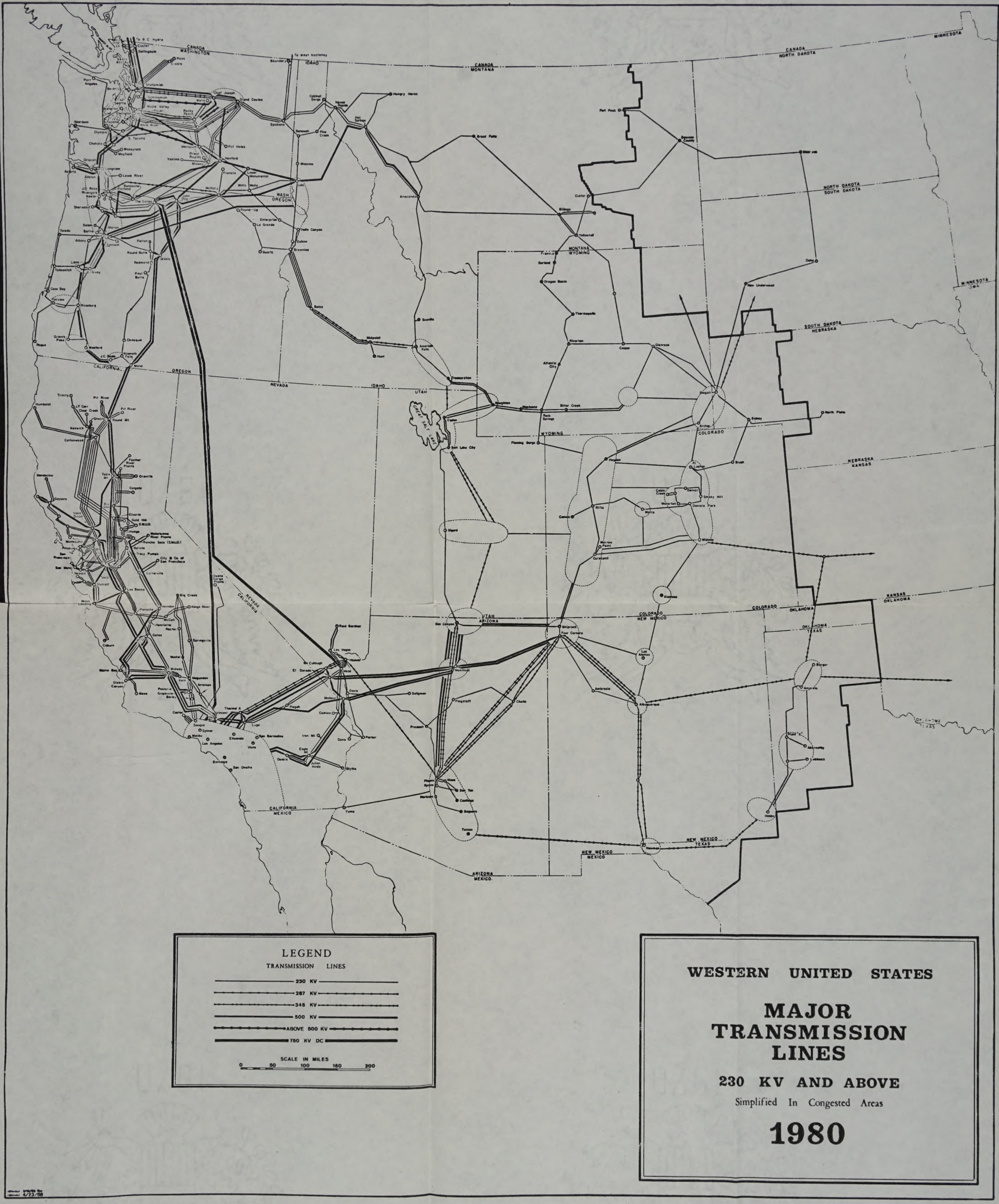
MAJOR TRANSMISSION LINES

Simplified In Congested Areas

1970



WESTERN UNITED STATES
MAJOR TRANSMISSION LINES
230 KV AND ABOVE
Simplified In Congested Areas
1970
LEGEND
TRANSMISSION LINES
230 KV
287 KV
345 KV
500 KV
750 KV DC
Federal Ownership
Public Ownership (Non - Federal)
No Identification Investor Ownership
SCALE IN MILES
0 50 100 150 200
CANADA WASHINGTON
CANADA MONTANA
CANADA NORTH DAKOTA
MINNESOTA
NORTH DAKOTA SOUTH DAKOTA
SOUTH DAKOTA NEBRASKA
MINNESOTA IOWA
NEBRASKA KANSAS
KANSAS OKLAHOMA
COLORADO OKLAHOMA
OKLAHOMA TEXAS
NEW MEXICO TEXAS
NEW MEXICO MEXICO
ARIZONA MEXICO
CALIFORNIA MEXICO
UTAH ARIZONA
COLORADO NEW MEXICO
MONTANA WYOMING
WASH OREGON
CALIFORNIA
OREGON
NEVADA
IDAHO
UTAH
WYOMING
COLORADO
NEVADA CALIFORNIA
4/23/68



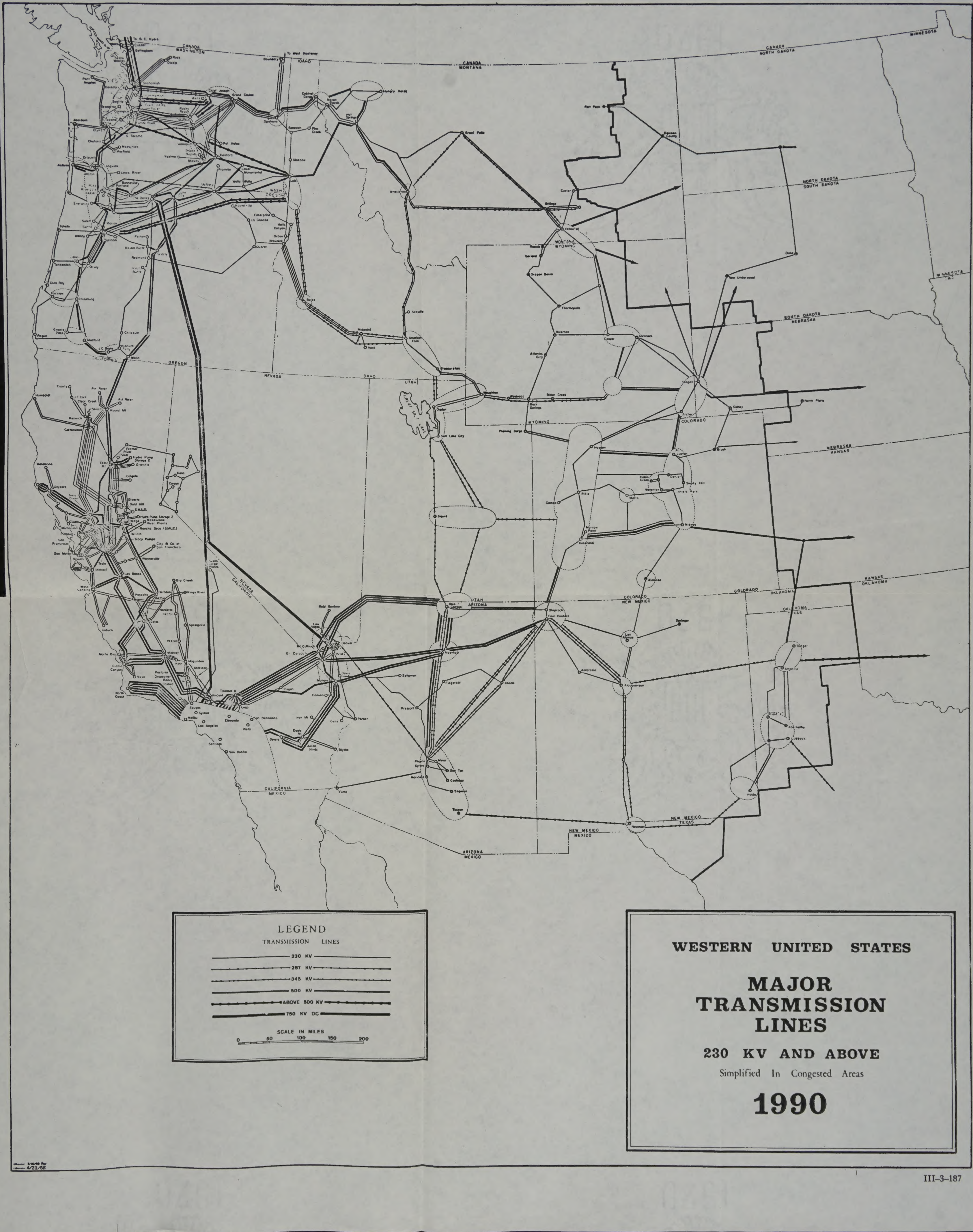
WESTERN UNITED STATES

MAJOR TRANSMISSION LINES

230 KV AND ABOVE

Simplified In Congested Areas

1980


WESTERN UNITED STATES
MAJOR TRANSMISSION LINES
230 KV AND ABOVE
Simplified In Congested Areas
1990
LEGEND
TRANSMISSION LINES
230 KV
287 KV
345 KV
500 KV
ABOVE 500 KV
750 KV DC
SCALE IN MILES
0 50 100 150 200

APPENDIX 5

STUDY OF COORDINATED PLANNING AND DEVELOPMENT

Prepared by Subcommittee on Coordinated Planning and Development

Structure of the Industry in the West Region

The ownership of systems of the West Region is shown by Power Supply Areas and for the Region in Table 1. Most of the systems in the West Region are interconnected; a few are isolated. The isolated systems are listed in Table 2. Generating capacity located in the West Region is principally conventional steam and hydro with two operating nuclear plants and only relatively small amounts of other types. The 1967 distribution by type of prime mover in each power supply area of the Region is shown in Table 3.

The highly diversified ownership of the utility systems and the high degree of interconnections that have been achieved have had a considerable influence on development of pooling and coordinating organizations in the West.

The interconnection of all but a few systems in the United States and Canada is an accomplished fact. The public dependence on electric service has made it necessary for the suppliers to provide a reliable and economic supply of electric energy, and interconnection between neighboring systems is a natural outgrowth of this need. Interconnections have been developing since electricity was introduced and the first transmission line was built. With extra-high voltage transmission lines shrinking the distance between systems, just as the railroad, the automobile, the airplane, and telephone, radio and television have shrunk the distance between all segments of the world, it seems that all systems in the United States will eventually be interconnected either by a-c or d-c lines. Now that most systems are interconnected and interdependent, it is important that the interconnected systems be operated reliably and economically.

Trends in the Development of Coordinating Mechanisms

The original systems started with one generator to serve a specific load. With the generator out of service the load could not be served, so it was immediately necessary to add a second generator for reliability. With the second generator the supplier had more capacity than load, so load was developed to go with the generation available. The next step in the development was for one system to be interconnected with an adjacent system in order to share excess generator capacity or reserve and to take advantage of more economical power sources. It also permitted sharing peak and weather diversity between the systems, and maintenance of equipment could be scheduled using all available sources of energy. The first interconnections were no more than a single line. As in the case of a single generator, it soon became necessary to build a second line to increase reliability. A system having an interconnection with one area soon found it advantageous to make a similar interconnection to another area, and this went on until the radial connections between the systems became loop systems. As systems in the United States became interconnected, operating problems developed and it was necessary for the operators of the various systems to solve these problems.

One of the earliest groups formed to solve problems resulting from interconnection was the *Northwest Power Pool* (*NWPP*). This pool has been organized since the early 1940's uniting systems in Utah, Montana, Idaho, Washington, Oregon and Canada. This pool was started with six companies and has expanded to include 18 systems, 16 of which are in the United States and two in Canada. Of the 18 systems, eight are investor-owned, three are municipal, three are utility districts, three are Federal and one Provincial. The pool operations are directed by an operating committee composed of one representative from each system, and a paid staff of coordinating engineers who devote full time to pool activities. The goal of the pool is to make the best use of the available facilities. The operating committee and the coordinating group of engineers meet bi-monthly, and the pool meetings are supplemented by conference telephone calls as required. Each pool member is kept informed on all pool operations. The coordinating group functions as

chairmen of pool meetings and conference calls. Each system prepares and circulates to all other members a weekly report showing such items as peak and average loads, actual generation streamflows, storage water levels, fuel supplies, maintenance planned and in progress, power and energy interchange with other systems, and other conditions existing or foreseeable which might affect pool operations. The committee agrees on principles and procedures for maintaining frequency and interchange control, interchange scheduling and accounting, maintenance schedules, relay settings, communication systems, generating reserves, reactive resources, voltage compensation and other items affecting pool operation.

An outgrowth of the operating program of the Northwest Power Pool is load shedding by underfrequency relays, so that area loads are matched to area generation, and in case of a major disturbance generation may be maintained and load restored in the shortest possible time.

Of the 18 systems which are members of the Northwest Power Pool, all had installed automatic load shedding equipment by the end of 1968.

There are three coordinating groups within the general area of the Northwest Power Pool and they are outgrowths of the Power Pool operations. They are the Intercompany Pool (INTERPOOL); the Pacific Northwest Utilities Conference Committee; and the Pacific Northwest Coordination Agreement.

The Intercompany Pool (INTERPOOL) is an operating group organized in 1947 within the Northwest Power Pool. The appendix includes a list of members. The requirements for participation include actual or contractual interconnections with other members of the group. Each party is represented on an Operating Committee. The pool was established for the purpose of coordinating power and energy resources, and studies of this nature are conducted periodically. Exchange of capacity and energy is made as permitted within the pool agreement.

The Pacific Northwest Utilities Conference Committee (PNUCC) is an informal organization composed of representatives from publicly-owned, cooperatively-owned and investor-owned electric utilities in the Pacific Northwest. Meetings of the Committee are called and presided over by an elected chairman, and funds provided by the members to cover Committee expenses are handled by an elected treasurer. The chairman and treasurer are the only Committee officers. Each utility shares in expenses on a voluntary pro-rated basis. Expenses incurred are those for Committee meetings, preparing and presenting testimony at the Congressional appropriations hearings and publishing of the Committee's "West Group Forecast" of power loads and resources each year. A subcommittee of the main Committee is assigned the task of preparing the annual loads and resources forecast. Activities of the Committee are limited essentially to (1) reviewing the plans and programs of the Federal agencies and providing support for needed power projects and transmission facilities where Federal appropriations are required, and (2) evaluation of loads and resources on an overall forecast basis each year. A significant function of the Committee in the early 1950's during the Korean War was to provide the organization through which a procedure for load curtailment under a power shortage situation in the Northwest was administered by the Defense Electric Power Administration.

The annual power loads and resources report prepared under sponsorship of the Committee is known as the "West Group Forecast." This report compiles the load forecasts of all of the utilities included in the West Group of the Northwest Power Pool. These forecasts, projected 10 years in advance, include a comparison for each year of forecasted loads with existing and scheduled generating plants. The report has proved to be very valuable in the long-range planning of regional power resources.

The *Pacific Northwest Coordination Agreement (PNCA)* group was organized in 1961 to coordinate the operation of power resources and transmission facilities. Initially the group operated under a series of short-term agreements. A long-term (35 years) agreement was signed in September, 1964. A list of members is included in the appendix. Additional parties may join when all existing parties so agree. Each party has a representative on a Coordination Contract Committee. The Committee determines the Firm Load Carrying Capability of the interconnected systems in accordance with the provisions of the agreement and makes studies and plans of the coordinated operation for the advice and information of the members. The agreement provides for an interchange of energy to maintain the determined Firm Load Carrying Capability, for the storage of energy in another party's reservoir and for the payments and entitlements between upstream and downstream plants. It also provides for coordination of the use of transmission facilities and establishes a uniform basis for charges for energy transfers. The

coordinated planning of maintenance outages is provided. The amount of and the extent of participation by each system in providing for forced outage reserve, energy reserve, and spinning reserve is established.

Representatives of utilities in the Pacific Northwest and Bonneville Power Administration have recently formed a Joint Power Planning Council to facilitate formal, long-range planning of generation and transmission requirements for the area. The Council has projected hydroelectric and thermal power requirements needed to satisfy load growth over the next 20 years, and expects to adopt a specific generation expansion plan for the next 10 years.

Also operating in the general area is the *Associated Mountain Power Systems* (AMPS). This is a planning group organized to make studies of transmission interconnections, which would make possible more efficient use of existing generating facilities and scheduling of future generating facilities together with coordination of generating plant operations and improvement of service continuity. The group has a joint Engineering and Operating Committee. Member companies have entered into a contract to construct certain transmission ties as a result of the coordinated planning of the group.

Other areas of the Western Region are covered by operating power pools, interconnection agreements or by various planning, operating or coordinating organizations. These are described in the following paragraphs.

The *Rocky Mountain Power Pool* (RMPP) was formed shortly after the end of World War II primarily for the purpose of coordinating operations of the member systems in Colorado, Wyoming and the panhandle area of Nebraska. Today, the pool includes representatives from the systems in Utah, Montana and the Black Hills area of South Dakota.

The pool is informal in that there is no master contract to which all members are signatory. There are numerous two-party and some three-party contracts which make possible the various capacity and energy transactions between the members of the pool.

The pool is operated under the over-all direction of a Policy Committee, with day-to-day operations supervised by an Operating Committee. Each member of the pool is entitled to membership on each of these committees. From time to time the Operating Committee appoints special subcommittees or task forces to study and make recommendations on specific problems which may arise.

In order to properly coordinate operations, the following items are representative of the work of the Operating Committee:

(1) Maintenance is coordinated by each member, submitting to the Operating Committee an advance copy of the proposed schedule for his system. These are tabulated and reviewed to make sure that the pool will have sufficient reserve capacity available to meet the projected peak loads at all times.

(2) To insure proper operation, the NAPSIC operating guides have been adopted as standard for the pool.

(3) At the bi-monthly meeting of the Operating Committee a full review is made of the status of load growth, maintenance projects and new facility construction by each system.

(4) Relaying of all circuit breakers which affect the reliability of the bulk power system is coordinated and periodically reviewed.

Nearly all of the hydroelectric generation in Colorado and Wyoming is owned and operated by the U.S. Bureau of Reclamation. All other systems are predominantly thermal. The pool has been particularly effective in coordinating the hydroelectric production of the Bureau and the thermal production of other members of the pool. In some instances surplus hydro is banked by the thermal systems and later returned to the Bureau.

Several wheeling contracts are also in effect in the Pool area. These make possible the best utilization of the transmission systems and eliminate some possible duplication of facilities.

The *Colorado Power Pool* (COLOPP) was organized in 1956 as an operating group. A list of members is shown in the appendix. No requirements for participation are included in the agreement. Each member is represented on an Operating Committee. The dispatcher of the company with the major load has jurisdiction over the operations and flows on the interconnections. Each system provides its own spinning reserve. The capability and timing of new capacity installations is coordinated among members.

The *Colorado Systems Coordinating Council* (CSCC) was organized on October 9, 1968. Membership is voluntary and open to all bulk power

systems in the State of Colorado. Bulk power systems are defined as systems which generate or transmit electric energy to points of distribution. The purpose of the Council is to coordinate the planning and operation of generating and transmission facilities in the State of Colorado, in order to achieve reliable operation and economic utilization of such facilities.

The Council operates through a ten-member steering committee, of whom three members represent municipal systems, three represent rural electric cooperative systems, three represent investor-owned systems, and one represents the United States Bureau of Reclamation. Officers include a Chairman, Vice-Chairman and Secretary, and are elected from the Steering Committee. The Steering Committee is directed to work in close coordination with the Western Systems Coordinating Council in: (1) accumulating data and performing studies of the operation of statewide interconnected systems, (2) accumulating data and making studies for transmission system interconnections and for construction of bulk power facilities, (3) reviewing and analyzing operating procedures to determine their conformity to procedures adopted by WSCC, and (4) recommending new or modified operating policies and procedures for guidance of member systems to insure closer coordination with WSCC. WSCC, Western Systems Coordinating Council, is described in following sections of this report.

The *New Mexico Power Pool* (NMPP) is a planning and operating group organized in 1941. Membership in the pool is voluntary. The appendix includes a list of members. Each pool member is represented on an Executive Committee and on an Operating Committee. The members of this pool cooperate in stability studies and coordinated emergency load reduction studies. Each member carries its own spinning reserve.

The *California Power Pool* (CALPP) is a planning and operating group, organized in 1964. The members are the three major investor-owned utilities in California, and are listed in the appendix. The California Power Pool provides a basis for continuous parallel interconnected operation between the area systems of the three parties.

There are no requirements for participation stated in the Agreement. Each member is represented on a Board of Control, which has established an Engineering and Operating Committee. In an advisory capacity, the Board of Control covers coordinated load projections, limited planning of reserves, and participation in the development of facilities. The Board's duties include planning for maximum benefits of all parties, procedures for exchange of information among parties, determining capability of interconnections under normal conditions, and prescribing metering, recording, billing and operating procedures.

The Agreement makes provisions for the sharing of capacity margins, provides for exchange of load and resource forecasts, maintaining spinning reserve and installed capacity, coordination of maintenance, purchase of firm capacity and energy, short-term firm service, emergency service, standby service, economy capacity and energy service, and energy interchange service.

A pool member is required to furnish service only out of its available capacity resources when it can do so without jeopardizing service to its own customers, and without interfering with its obligations to a third party. System dispatching is done on an individual system basis. Load shedding and tie line control practices are coordinated in accordance with rulings by the Board of Control.

The *Southern California Municipal Group* consists of four municipalities as listed in the appendix. The four municipalities are interconnected and the group agreements make provision for the supplying of emergency reserves, including spinning reserves, economy energy and other transactions to meet operating needs between the municipalities.

The City of Los Angeles through its Department of Water and Power handles the Hoover and Canadian entitlement for the other three cities, and will also handle the Pacific Northwest power for the municipalities over the 750 kv direct-current transmission line. The cities of Glendale, Burbank, Pasadena and Los Angeles, together with the Southern California Edison Company, participate in the ownership of the 750 kv d-c line. Los Angeles is constructing the southern portion of the line and will be the operating agency.

The membership list of all pools is shown in the appendix and the inter-relationship of the various pools is shown in Table IV and Figures 1 and 2. Some of these pools have extensive contractual agreements, while others are quite informal. However, all carry out coordinated operation, maintenance and planning in some degree. These operations have led to the formation of other and larger planning groups, some of which extend beyond the boundaries of the Western Region.

A western region group primarily concerned with planning the most effective use of regional energy resources is the *Western Energy Supply and Transmission Associates* (WEST), which now consists of 23 utilities in nine southwestern states. At the present time the membership of WEST is made up of 12 investor-owned, 5 municipally-owned, 3 REA Generation and Transmission Systems, 2 Irrigation Districts, and 1 State Authority. WEST itself does not construct or own any facilities, but members of WEST have planned together to build jointly-owned plants and transmission lines.

The objectives of WEST Associates may be summarized as follows:

(1) To provide for integrated regional planning of generation and transmission.

(2) Work with other power suppliers, both within the area and in adjacent areas, in an effort to coordinate plans.

(3) Provide a means for members to obtain the economies of scale by participation in jointly-owned large generating plants, but at the same time protect the right of individual members for self-sufficiency.

(4) Provide means to use diversity and reduce reserves.

The accomplishments of WEST Associates to date consist of the installation of two 750 mw coal-fired steam units at the Four Corners site in New Mexico, and agreement to construct two 750 mw coal-fired units at the Mohave site on the Colorado River, and the construction of hundreds of miles of 345 kv and 500 kv transmission lines to make this power available to the various participants in the two jointly-owned projects.

WEST operates with a Board of Directors, a Management Committee, Planning Committee, Legal Committee, and Public Relations Committee. Members are assessed dues, to cover operation of the organization, in proportion to the size of their operations.

As a result of the proposed extensions of interconnections between regions in the United States, the *North American Power Systems Interconnection Committee* (NAPSIC) was formed in January, 1963, to coordinate the operation of the massive network. NAPSIC is an informal, voluntary organization of operating personnel representing the interconnected systems or regions in electrical synchronism. Representation at present, consists of two members from each region. These operators have met regularly and have developed basic guides for interconnected operation to maintain maximum reliability from the systems as constructed.

Another outgrowth of the need to have systems coordinate their operation and planning is the *Western Systems Coordinating Council* (WSCC) formed in early 1967 by some 40 systems in 13 western states and a province of Canada, very closely identified with the West Region represented by the West Regional Advisory Committee. There are some differences along the eastern boundary and, of course, the Canadian systems are not represented on the West Regional Advisory Committee.

The *Western Systems Coordinating Council* (WSCC) is a voluntary council open to all bulk power suppliers in the 13 U.S. western states and the Canadian province of British Columbia. As of January 1, 1969, there were 39 member systems. By type of ownership they are classified as follows:

Canadian Provincial System	1
U.S. Federal Agencies	3
REA G. & T. Systems	3
State and Public Utility District	8
Municipal Systems	6
Investor-owned systems	18

A complete listing of the membership of Western Systems Coordinating Council is shown in the appendix with chart outlining the structure of the Council.

Relative size of the various classes of member systems is indicated by the installed generating capacity. Totals for 1967 were as follows:

	Kilowatts of installed capacity
Cooperatives	261,000
Federal	10,552,000
Investor-Owned	28,189,000
Municipal	8,847,000
State or Province	2,324,000
Total	50,173,000

The purpose of this Council is to promote the reliable operation of interconnected bulk power systems. It is truly a coordinating council and has no specific planning responsibility. All planning for future generation and transmission facilities is the responsibility of the individual member systems and whatever planning groups with which they may be associated. However, before making final commitments for construction, such planning is reported to the Council, where studies are made to determine the effect of planned changes on the reliability of the whole western regional bulk power network.

Each system is entitled to a representative of its choice on the Council and from this group are selected three officers and an Executive Committee to direct and coordinate the activities of the Council. A Planning Coordination Committee is assigned the duty of accumulating data and performing regional studies of the interconnected systems to determine the electrical stability and associated reliability of the regional bulk power network, and to formulate reports and recommendations based on these studies. An Operations Committee reviews and analyzes operating procedures and problems relating to the reliability of the operation of the interconnected bulk power systems, and recommends new or modified operating policies and procedures for the guidance of the member utilities.

A Public Information Committee was formed more recently. Its objective is to obtain factual data concerning member systems and their operations and, particularly in the case of emergencies, disseminate these data immediately to the public press and other news media so that the public is kept correctly informed of power system matters of general interest.

Still more recently a committee was formed to provide liaison with the Western Conference of Public Service Commissions. This consists of the Vice Chairman of WSCC and the Chairmen of the Planning Coordination Committee and the Operations Committee. Each of the other standing committees has a representative from each Council member and has subcommittees and task forces to review specific problems, but the committee as a whole makes its findings and recommendations to the Council for action. The Western Systems Coordinating Council provides a forum for coordinating the planning and operations of the bulk power supply systems in the 13 western states; however, the actual construction of the systems is the responsibility of each individual system. The council provides the means for each system to know how its plans will affect other systems and how other systems' plans may affect it. With this knowledge it will be possible to develop systems for the greatest reliability and economy.

Within WSCC there is no central dispatching center for direct control of generating plants and energy transfers. These functions are the responsibilities of individual systems or pool organizations. Future trends in central dispatch centers cannot be forecast at this time. As noted above, the Planning Coordination Committee collects data for regional studies of load flow and stability. Both data and studies cover seven years into the future. From these data and studies, it is planned that the existence of any areas of weakness or deficiency will be found, and recommendations for their alleviation or elimination can be made. The relationship of the Council to other coordinating groups is shown geographically in Figure 3.

As the Western Systems Coordinating Council has developed as a result of interconnected systems and areas, it became apparent that some form of organization should be established as a clearing house for the problems of the interconnected regions of the country, and this year the *National Electric Reliability Council* (NERC) was formed on June 11, 1968. Its purpose is to encourage and assist the development of direct or indirect interregional reliability arrangements among regional organizations or their members; to exchange information with respect to planning and operating matters relating to the reliability of bulk power supply; to periodically review regional and interregional activities on reliability; to provide independent review of interregional matters referred to it by regional organizations; and to provide information to the Federal Power Commission and, where appropriate, to other Federal agencies with respect to matters considered by the Council.

Future Coordinating Agreements or Arrangements

The area represented by the West Regional Advisory Committee is characterized by long distances between load centers and between load centers and hydroelectric sites. At present fossil-fuel plants are generally close to load centers but in certain areas there are developing an increasing number of coal-fired mine mouth plants located at considerable distances from the loads they supply. The area includes the sparsely settled mountainous areas of the Rockies, the Sierras, and the Cascades; the desert areas of the Southwest; the Great Basin; the more populous areas of the Columbia River system, the Colorado River system, part of the Missouri River systems, and the costal rivers of Washington, Oregon and California; as well as the major load centers around San Diego, Los Angeles, San Francisco, Portland and Seattle, all ports on the Pacific Coast. The present power supply for the area is predominantly hydro in the Northwest, thermal in the South and Southwest, while the Northeast portion of the area

and the Rocky Mountain area are supplied by a mixture of hydro and thermal units. Major coal fields are in eastern Montana, most of Wyoming, western Colorado, eastern Utah and the Four Corners area of Arizona and New Mexico. Most of these coal fields are in water-short areas. Because of the distances involved when using coal, and the diminishing economical hydro developments available, the coastal systems are looking to large nuclear plants to supply their future needs. This may be further dictated by possible limitations on the use of fossil fuels because of air pollution. Electrically it is best to have generation close to load, but other considerations may require the plants to be located some distance from the metropolitan area loads they serve.

Under these conditions the Western Systems Coordinating Council has been formed and has established a basis for coordinated planning, development and operation of the systems in the 13 western states. Through its members it will continue to collect data on loads and resources seven years in advance. It will also collect data on proposed generation and transmission facilities. Based on these data, studies performed by the Planning Coordination Committee will suggest possible optimum arrangement of interconnections between the various systems and areas which could improve reliability and stability. Also, these data will be available to all systems and can be used with intra-system studies to disclose the effect of planned additions on interconnections and on other systems.

The Operations Committee will continue to analyze operations on the whole interconnected network in order to anticipate possible trouble areas and to initiate programs to eliminate them. The committee, when requested to do so by the managements of the affected systems, will assist in analyzing major bulk power system outages with the objective of determining the causes and recommend means of avoiding such interruptions in the future. The committee will also survey the protective relay settings specified by the owners of key transmission ties with the objective of obtaining proper coordination and the greatest reliability on the network. Improved communications between dispatching centers will also be encouraged where existing communications are found inadequate to cope with the problems of interconnected operation.

Each system in the area is responsible for planning the additions to its system to meet its load requirements. Some systems are of such a size that they can use the largest equipment and the highest voltage available. Other systems, however, are not large enough to take advantage of the economies of size in generating equipment. The ownership of such systems may be Federal, public non-Federal, utility company, a combination of two or more of the above, or a generating company owned by one or more parties. Such systems, by various methods of joint participation, will be able to gain some economies by using larger machines, but because of the distances between systems and loads and the size of the loads, many cannot economically install the largest units presently available. There are several approaches to joint use of generating units, and the plan used will depend on the systems involved, their financial setup and the Federal and state regulations under which they operate.

As has been noted, all the systems in the West Regional Advisory Committee area are operating in parallel. This network is formed primarily from four different pools or areas (see Figure 1). At the present time, this network is connected to the Interconnected Systems Group by lines from Montana and Wyoming. Studies have been made for connections between Colorado and Kansas and between Colorado and the Southwest Public Service system.

The Western Systems Coordinating Council is developing planning and operating criteria designed to improve system reliability. Such criteria at the very least will relate to interconnection reliability standards, operating reserves and load shedding practices. Although the Council has initiated work on formulation of standards in the areas referred to, no concrete proprosals are expected until late 1969.

Future Coordinating Requirements

In the next two decades the large increase in total generating requirements, the large size of individual units and higher voltage of transmission lines, together with the greater emphasis on retaining or enhancing the quality of the environment, will make close coordination of planning and operation imperative. To meet these requirements, stepped up research and development must be done not only in the field of materials and equipment, but also in methods and procedures.

The group effort of an organization such as Western Systems Coordinating Council is a good vehicle for motivating this research and development.

It is also possible that existing power pools may be restructured to meet changing needs and patterns of growth. There will need to be better communication and faster dissemination of information among power systems so that interconnection operating decisions can be made more intelligently.

Two examples of how greater reliability will be assured are the criteria for system planning and interconnections and the highly sophisticated transient stability computer program now in the process of being expanded by members of the Western Systems Coordinating Council. Load flow computer programs have been developed to handle as many as 1400 or 2000 busses.

More attention will be given in the future to the distribution of spinning reserve with respect to both load and generation areas. Consideration will also be given to the rate of response of the spinning reserve units in assigning the reserve quotas.

The role of computers in the future load dispatch centers will probably be developed on a step-by-step basis. In the early stages it will perhaps monitor many pertinent factors, such as power flows as related to relay settings, or rate of change of frequency or power flow, reversal of power flow, etc., and call these to the attention of the dispatcher. At some later time it may be that the computer may initiate corrective measures.

Problems and Solutions

Within the West Region, distances between major load centers are usually great. This presents an economic problem in order to take advantage of seasonal diversities which exist between the northern and southern portions of the Region. Currently there is also a surplus of hydro power in the Pacific Northwest during the summer months, when it could be used in the southern areas to replace power generated by thermal plants. After lengthy studies and negotiations among the utilities of the Pacific Northwest and in California and Arizona, agreement was reached on sale and interchange arrangements. The negotiations have resulted in the construction of two 500 kv a-c transmission lines, linking the Pacific Northwest and the California systems. These lines are now in operation. Also authorized are two 750 kv d-c transmission lines. One of these is under construction and will link the Pacific Northwest and the Southern California area, while the other is planned to join the Pacific Northwest to the Colorado River area at Hoover Dam basically for the purpose of utilizing the diversity which may exist between the Pacific Northwest and the Arizona area. Construction costs of the four lines are shared by the Federal systems (BPA and USBR), Municipal systems such as those in the Southern California Municipal Group and by investor-owned utilities in the Pacific Northwest and in California and Arizona.

A further problem which has aroused much interest is the question of how small systems can participate in economies inherent in large-scale power developments. Small systems that purchase their total requirements from neighboring suppliers will share in such benefits through the normal wholesale rate regulatory process. Small systems which generate all or most of their requirements have been able to install larger, more efficient units by purchasing deficiency capacity for a period of time, selling excess capacity from a new unit, and obtaining reserve capacity to replace power from the large unit when it is removed from service during emergencies or normal maintenance periods.

Small systems may also be able to act in concert to install large units at much lower cost than would be possible if they supplied all their own needs from generating capacity within their system. To accomplish this objective, these systems may find it desirable to participate in wheeling arrangements to deliver power from such jointly sponsored plants without themselves constructing transmission lines. This type of wheeling arrangement, which has received acceptance by utilities in the Rocky Mountain Power Pool provides good utilization of transmission lines by avoiding duplication of facilities and land use. Coordinated planning and development among large and small systems on an area-wide basis provides the best assurance of optimum resource development.

This problem has been solved to some extent in the Pacific Northwest through joint or "partnership-type" arrangements for new power plants. Typical of this are long-term power contracts by systems in Washington and Oregon for a share of the output from four large hydroelectric developments constructed on the Columbia River by non-federal public agencies. Under these participation agreements the purchaser generally contracts to take a percentage of the plant output in return for paying the same percentage of the plant's annual cost. The terms of these agreements are variable depending upon the various circumstances.

The purchaser usually receives a percentage of all components of the plant capabilities, capacity, energy, pondage and associated transmission facilities. He molds this into his system as one of his own plants and has full control of its scheduling. Under this type arrangement the owner may reserve the right to withdraw power for his own use up to specified maximum amounts by sufficient notice or may have a fixed percentage purchased by years on a declining basis. Contracts signed in advance of construction can serve as a guarantee for the financing of the plant construction.

A further but different example of joint participation in the Northwest was the construction of Hanford project by Washington Public Power Supply System. This is an operating agency authorized under Washington State Law which is empowered among other things to build and operate generating facilities. Participation in a development is voluntary in that a municipal, public utility district, or rural electric cooperative may join in a venture or not as it chooses. The output of Hanford plant is shared equally between two groups of utilities—five investor owned utilities and 76 publicly-owned utilities with each paying one-half the costs. The output is exchanged with Bonneville Power Administration, which receives the power and provides transmission and back-up reserves and delivers to each purchaser the amount of power his payments entitle him to at BPA rates.

The Centralia thermal electric plant is another example of joint participation by utilities, public and private, in a Pacific Northwest power plant. The Centralia plant, consisting of two units with total capacity of 1400 mw, will be owned by four private utilities and five public agencies. Each participant will finance and directly own, as tenants in common, his agreed upon share of the plant for the life of the plant. This type of arrangement differs from the two previously described types of joint participation. In the Columbia River projects joint participation is obtained through sale of parts of the plant output and in the Hanford project through sale and exchange of the plant output with the sponsoring organizations retaining ownership of the plants and eventually, with expiration of the sales agreements, obtaining the full plant output.

The Centralia project is the first step in a program of cooperative thermal projects in the Pacific Northwest. A Joint Power Planning Council formed among the utilities in the Northwest is planning for the coordinated future construction of large thermal generating plants scheduled to meet the area requirements. These plants will be sized to take advantage of economies of scale, timed to meet area requirements and located to make efficient use of the area's transmission grid. In conjunction with this program the Centralia project was advanced from the participant's required schedule to a schedule necessary to meet the area requirements. The disposition of the output of the plant during this early period will be to the Government to meet Northwest area requirements, and part of the plant output has been sold to the Government to provide a ten-year supply of power to the Central Valley Project in California. Joint participation in the other jointly-planned projects is anticipated through various types of arrangements. Through such arrangements each utility in the area, public and private, will be able to participate in one or more of the several plants being planned; however, for the most part, it is contemplated that the smaller distributor type public agencies will continue to purchase their future power supply from the Bonneville Power Administration.

Joint ownership of power generating facilities has also been practiced in the construction of the large generating facilities such as San Onofre nuclear generating plant, in the Four Corners area of New Mexico, and is also provided at the Mohave plant and proposed for others to be built along the Colorado River.

The role of load shedding in providing reliable service is generally recognized in the western states. Nearly all major systems have the equipment in service at this time. In general, automatic load shedding begins when the frequency drops to a predetermined value of approximately 59.5 Hz and remains there for a predetermined time. Load is dropped in blocks with additional blocks being dropped with further reductions in frequency. Schedules of load shedding of the various systems are compatible. When the frequency approaches 58.0 Hz steam units may experience trouble with vital auxiliaries such as draft fans and boiler-feed pumps. More drastic steps must then be taken to avoid a cascading type outage and expedite return of interconnected systems to normal operation. Load shedding practices are being coordinated thru the WSCC.

Interregional Coordination

Interregional ties will probably develop when they can be economically justified. For example, a study was made of a tie between Public Service Company of Colorado and Southwestern Public Service Company. At that time the cost of the tie as related to the available summer-winter diversity exchange (after giving consideration to maintenance schedules) was not economical. This tie will be reviewed again in the next year or two.

A preliminary study of a tie from Public Service Company of Colorado to Kansas Gas and Electric Company indicated that, until stronger east-west ties are built through Nebraska, too much line capacity is used up by inadvertent east-west power flows. Here again this project will be reviewed at a later date.

All of the major electric systems in the West are interconnected through at least one of the many power pools or coordinating groups. The Western interconnected systems were lightly tied to the Eastern systems of the United States at three points in early 1967 (East-West Tie). These connections are at 115 kv at Fort Peck and 230 kv at the Bureau of Reclamation's Yellowtail Plant in Montana and at Stegall, Nebraska. There are no connections between the West Region and Southwest or Texas systems (except El Paso).

The East-West interconnection permits synchronized parallel operation of about 97 percent of the generation capacity in the United States. However, the ties are so light that interruptions are frequent. Problems arising from this tie continue to receive the attention of the East-West Tie Closure Task Force. This problem also is under active study by the Operations Committee and Planning Coordination Committee of the WSCC. Working with this task force of the Operations Committee is a representative from MAPP.

TABLE 1

West Region—Power System Structure

Type of ownership	Number of systems	1967 Installed capacity, mw	1967 Energy generated, mwh
PSA 31:			
Federally Owned	1	209	775, 906
Investor Owned	7	488	1, 938, 039
Municipally Owned	29	38	61, 875
Rural Electric Coop	19	5	12, 764
State Owned	5	60	180, 928
Total	61	800	2, 969, 512
PSA 32:			
Federally Owned	1	258	761, 350
Investor Owned	4	1, 654	6, 309, 897
Municipally Owned	35	267	940, 168
Rural Electric Coop	28	231	1, 374, 344
State Owned	0	0	0
Total	68	2, 410	9, 385, 759
PSA 36:			
Federally Owned	0	0	0
Investor Owned	4	1, 515	6, 382, 990
Municipally Owned	9	218	488, 516
Rural Electric Coop	15	80	240, 885
State Owned	0	0	0
Total	28	1, 813	7, 112, 391

TABLE 1—Continued

Type of ownership	Number of systems	1967	
		Installed capacity, mw	Energy generated, mwh
PSA 39:			
Federally Owned	1	24	35, 136
Investor Owned	4	902	3, 653, 204
Municipally Owned	6	29	26, 724
Rural Electric Coop	12	52	74, 816
State Owned	0	0	0
Total	23	1, 007	3, 789, 880
PSA 30:			
Federally Owned	2	335	1, 312, 729
Investor Owned	3	566	3, 620, 106
Municipally Owned	0	0	0
Rural Electric Coop	0	0	0
State Owned	0	0	0
Total	5	901	4, 932, 835
PSA 41:			
Federally Owned	4	281	1, 535, 323
Investor Owned	9	2, 181	9, 455, 270
Municipally Owned	19	71	166, 557
Rural Electric Coop	6	28	95, 004
State Owned	0	0	0
Total	38	2, 561	11, 252, 154
PSA 42:			
Federally Owned	1	3, 011	23, 764, 747
Investor Owned	1	636	3, 454, 946
Municipally Owned	6	2, 780	11, 748, 890
Rural Electric Coop	1	....	3
State Owned	0	0	0
Total	9	6, 427	38, 968, 586
PSA 43:			
Federally Owned	1	1	1, 837
Investor Owned	1	321	1, 062, 285
Municipally Owned	6	2, 116	10, 468, 645
Rural Electric Coop	1	2	1
State Owned	0	0	0
Total	9	2, 440	11, 532, 768
PSA 44:			
Federally Owned	3	2, 915	19, 925, 813
Investor Owned	3	1, 609	6, 569, 588
Municipally Owned	4	905	2, 040, 319
Rural Electric Coop	0	0	0
State Owned	0	0	0
Total	10	5, 429	28, 535, 720

TABLE 1—Continued

Type of ownership	Number of systems	1967 Installed capacity, mw	1967 Energy generated, mwh
PSA 45:			
Federally Owned	1	388	1, 092, 637
Investor Owned	0	0	0
Municipally Owned	1	137	405, 234
Rural Electric Coop	0	0	0
State Owned	0	0	0
Total	2	525	1, 497, 871
PSA 46:			
Federally Owned	2	1, 037	5, 909, 878
Investor Owned	3	8, 753	35, 663, 585
Municipally Owned	10	1, 119	6, 898, 762
Rural Electric Coop	0	0	0
State Owned	1	53	433, 958
Total	16	10, 962	48, 906, 183
PSA 47:			
Federally Owned	0	0	0
Investor Owned	5	9, 608	44, 276, 410
Municipally Owned	6	3, 825	15, 716, 645
Rural Electric Coop	1	1	4, 313
State Owned	0	0	0
Total	12	13, 434	59, 997, 368
PSA 48:			
Federally Owned	4	2, 606	6, 804, 334
Investor Owned	7	2, 483	9, 311, 155
Municipally Owned	3	618	1, 665, 135
Rural Electric Coop	1	97	197, 956
State Owned	0	0	0
Total	15	5, 804	17, 978, 580
West Region Totals:			
Federally Owned	21	11, 065	61, 919, 690
Investor Owned	51	30, 716	131, 697, 475
Municipally Owned	134	12, 123	50, 627, 470
Rural Electric Coop	84	496	2, 000, 086
State Owned	6	113	614, 886
Total	296	54, 513	246, 859, 607

TABLE 2

West Region—Isolated Systems

Name	Type of ownership [1]	1967 Installed capacity, kw	1967 Peak demand, kw	1967 Energy generated, mwh
PSA 31:				
Julesburg Power & Light Dept., Colorado	M	3,721	1,640	7,055
Kimball City, Nebraska	M	5,900	3,300	15,073
Sydney Public Utilities, Nebr	M	8,632	4,750	21,688
Total		18,253	[2] 9,690	43,816
PSA 32:				
Burlington Light & Water, Colorado	M	5,804	2,450	10,505
Delta Mun. Light & Power, Colo	M	4,992	3,270	15,448
LaJunta Mun. Utilities, Colo	M	12,728	8,000	34,828
Springfield, Colorado	M	1,992	4,945	4,700
Total		25,516	[2] 18,665	65,481
PSA 36:				
Brownfield Mun. Light & Power, Texas	M	15,880	8,000	34,364
Canadian Light & Power, Texas	M	6,064	2,550	7,796
Clayton, New Mexico	M	4,590	2,100	9,946
Crosbyton, Texas	M	4,742	2,190	6,610
Floydada, City of, Texas	M	6,140	3,600	12,500
Lubbock Power & Light, Texas	M	157,150	70,000	365,492
Plains, City of, Texas	M	1,516	900	2,700
Tucumcari Light & Power, New Mexico	M	13,050	7,300	29,067
Tulia Power & Light, Texas	M	8,504	4,650	20,041
Total		217,636	[2] 101,290	488,516
PSA 39:				
None				
PSA 30:				
None				
PSA 41:				
Atlanta Power Co., Idaho	I	120	N.R.	[3] 33
Carlin City Power, Nevada	M	3,592	N.R.	[3] 652
Total		3,712		685
PSA 42:				
None				
PSA 43:				
Chelan Co. P.U.D., Stehekin, Washington	M	250	180	537
PSA 44:				
None				
PSA 45:				
None				
PSA 46:				
Austin Light & Power, Nev	I	400	N.R.	N.R.

See footnotes at end of table.

356-240 O - 70 - 32

TABLE 2—Continued

Name	Type of ownership [1]	1967 Installed capacity, kw	1967 Peak demand, kw	1967 Energy generated, mwh
PSA 47:				
Ely Light & Power, Nevada	I	1,830	1,830	2,841
Eureka Light & Power, Nevada	I	550	N.R.	N.R.
Southern California Edison Co., Santa Catalina, Calif.	I	5,055	2,250	7,922
Total		7,435	[2] 4,080	10,763
PSA 48:				
Morenci Water & Electric Co., Arizona	I	0	0	[4] 0
WEST Region Total		273,202	[2] 133,905	609,798

[1] F—federally owned; I—investor owned; M—municipally owned; R—rural electric coop.; S—State owned.
[2] Noncoincident.
[3] Last reported for 1965.
[4] Receives energy from Phelps Dodge Corporation.

TABLE 3

West Region—Generating Capacity by Type of Prime Mover

[1967 Data]

PSA	Hydro: Conventional: Installed capacity, kw	Hydro: Conventional: Generation, mwh	Hydro: Pumped storage: Installed capacity, kw	Hydro: Pumped storage: Generation, mwh	Thermal: Diesel: Installed capacity, kw	Thermal: Diesel: Generation, mwh	Thermal: Gas turbine: Installed capacity, kw	Thermal: Gas turbine: Generation, mwh	Thermal: Conventional Fossil fueled: Installed capacity, kw	Thermal: Conventional Fossil fueled: Generation, mwh	Thermal: Geothermal: Installed capacity, kw	Thermal: Geothermal: Generation, mwh	Thermal: Nuclear: Installed capacity, kw	Thermal: Nuclear: Generation, mwh	Total: Installed capacity, kw	Total: Generation, mwh
31	211, 967	788, 670	0	0	46, 923	50, 030	0	0	541, 275	2, 130, 812					800, 165	2, 969, 512
32	322, 532	927, 443	300, 000	(−62, 751)	96, 388	126, 275	0	0	1, 690, 942	8, 394, 792					2, 409, 862	9, 385, 759
36	0	0	0	0	102, 251	138, 747	69, 921	276, 285	1, 640, 464	6, 697, 359					1, 812, 636	7, 112, 391
39	24, 300	35, 136	0	0	1, 004	2, 783	13, 000	0	969, 150	3, 751, 961					1, 007, 454	3, 789, 880
30	813, 590	4, 833, 703	0	0	2, 750	61	0	0	84, 550	99, 071	0	0	0	0	900, 890	4, 932, 835
41	1, 775, 355	7, 992, 382	0	0	59, 864	35, 205	0	0	725, 906	3, 224, 567	0	0	0	0	2, 561, 125	11, 252, 154
42	6, 426, 730	38, 968, 583	0	0	733	3	0	0	0	0	0	0	0	0	6, 427, 463	38, 968, 586
43	2, 240, 171	11, 534, 561	0	0	2, 460	190	0	0	197, 500	(1, 983)	0	0	0	0	2, 440, 131	11, 532, 768
44	4, 380, 097	26, 500, 244	0	0	3, 496	(−278)	0	0	185, 140	(4, 729)	0	0	860, 000	2, 040, 483	5, 428, 733	28, 535, 720
45	499, 500	1, 497, 142	0	0	0	0	0	0	25, 000	729	0	0	0	0	524, 500	1, 497, 871
46	4, 484, 523	27, 658, 074	25, 200	38	31, 616	22, 313	27, 000	14, 204	6, 278, 151	20, 567, 570	55, 363	316, 310	60, 000	327, 674	10, 961, 853	48, 906, 183
47	1, 031, 815	7, 243, 568	0	0	49, 911	10, 965	58, 144	38, 908	11, 836, 272	52, 408, 948	0	0	457, 500	294, 979	13, 433, 642	59, 997, 368
48	2, 673, 690	7, 097, 909	7, 200	1, 282	90, 178	118, 928	11, 250	33, 339	3, 022, 032	10, 727, 122	0	0	0	0	5, 804, 350	17, 978, 580
West Region	24, 884, 270	135, 077, 415	332, 400	(−61, 431)	487, 574	505, 222	179, 315	362, 736	27, 196, 382	107, 996, 219	55, 363	316, 310	1, 377, 500	2, 663, 136	54, 512, 804	246, 859, 607

conventional & PS

1970 30,000,00 160 Gwh

1985 50,000 200 Gwh

APPENDIX

Organization of the Utility Industry—Western United States

California Power Pool (CALPP)
- Pacific Gas and Electric Co.
- San Diego Gas and Electric Co.
- Southern California Edison Co.

Southern California Municipal Group (SCMG)
- City of Los Angeles
- City of Burbank
- City of Glendale
- City of Pasadena

Colorado Power Pool (COLOPP)
- Public Service Company of Colorado (Central System)
- City of Colorado Springs
- Southern Colorado Power Division of Central Telephone and Utilities, Inc.

Pacific Northwest Coordination Agreement (PNCA)
- Bonneville Power Administrator
- Division Engineer, North Pacific Division, Corps of Engineers, Department of the Army
- The United States Entity, designated pursuant to Article XIV of the Treaty
- City of Eugene, Oregon
- City of Seattle, Washington
- City of Tacoma, Washington
- Public Utility District No. 2 of Grant County, Washington
- Public Utility District No. 1 of Chelan County, Washington
- Public Utility District No. 1 of Pend Oreille County, Washington
- Public Utility District No. 1 of Douglas County, Washington
- Public Utility District No. 1 of Cowlitz County, Washington
- Puget Sound Power and Light Co.
- Portland General Electric Co.
- Pacific Power and Light Co.
- The Washington Water Power Co.
- The Montana Power Co.
- Colockum Transmission Co., Inc., a subsidiary of Aluminum Company of America

Northwest Power Pool (NWPP)
- (Operating Committee—Voluntary Participating Systems)
  - Bonneville Power Administration
  - British Columbia Hydro & Power Authority
  - Eugene Water & Electric Board
  - Idaho Power Co.
  - Montana Power Co.
  - Pacific Power & Light Co.
  - Portland General Electric Co.
  - Puget Sound Power and Light Co.
  - PUD No. 1 of Chelan County
  - PUD No. 1 of Douglas County
  - PUD No. 2 of Grant County
  - Seattle Department of Lighting
  - Tacoma Public Utilities—Light Division
  - U.S. Army Corps of Engineers—North Pacific Division
  - USBR—BPA (Southern Idaho)
  - Utah Power & Light Co.
  - Washington Water Power Co.
  - West Kootenay Power & Light Co.

The Intercompany Pool (INTERPOOL)
- Pacific Power and Light Co.
- Portland General Electric Co.
- Puget Sound Power and Light Co.
- The Washington Water Power Co.

Associated Mountain Power Systems (AMPS)
- Idaho Power Co.
- The Montana Power Co.
- Pacific Power and Light Co.
- Utah Power and Light Co.
- The Washington Water Power Co.

New Mexico Power Pool (NMPP)
- Community Public Service Co.
- El Paso Electric Co.

Plains Electric G & T Cooperative, Inc.
Public Service Company of New Mexico
USBR—Rio Grando Project

Pacific Northwest Utilities Conference Committee (PNUCC)
- Central Lincoln PUD, Newport, Oregon
- Chelan County PUD, Wenatchee, Washington
- Coos-Curry Electric Cooperative, Inc., Coquille, Oregon
- Douglas County PUD, Bridgeport, Washington
- Eugene Water & Electric Board, Eugene, Oregon
- City of Forest Grove, Forest Grove, Oregon
- Grant County PUD No. 2, Ephrata, Washington
- Grays Harbor County PUD, Aberdeen, Washington
- City of McMinnville Water & Light Department, McMinnville, Oregon
- Milton-Freewater Utilities, Milton-Freewater, Oregon
- Pacific Power and Light Co., Portland, Oregon
- Portland General Electric Co., Portland, Oregon
- Puget Sound Power & Light Co., Bellevue, Washington
- Seattle City Light, Seattle, Washington
- Snohomish County PUD, Everett, Washington
- Tacoma City Light, Tacoma, Washington
- The Washington Water Power Co., Spokane, Washington
- Washington Public Power Supply System, Kennewick, Washington
  - *Member Systems*
    - Benton County PUD, Kennewick, Washington
    - Clallam County PUD, Port Angeles, Washington
    - Ferry County PUD, Republic, Washington
    - Franklin County PUD, Pasco, Washington
    - Kittitas County PUD, Ellensburg, Washington
    - Klickitat County PUD, Goldendale, Washington

Rocky Mountain Power Pool (RMPP)
- Public Service Company of Colorado
- Pacific Power & Light Co. (Wyoming Division)
- USBR—Region 4
- USBR—Region 7
- Montana Power Co.
- Consumers Public Power District
- Southern Colorado Power Division of Central Telephone & Utilities Corp.
- Colorado Springs Department of Public Utilities
- Utah Power & Light Co.
- Black Hills Power & Light Co.
- Tri-State G & T Assn., Inc.
- Colorado-Ute Electric Assn., Inc.
- Cheyenne Light, Fuel & Power Co.
- Western Colorado Power Co.

Western Energy Supply and Transmission Associates (WEST)
- Arizona Public Service Co.
- Department of Water & Power, City of Los Angeles
- El Paso Electric Co.
- Nevada Power Co.
- Public Service Company of Colorado
- Public Service Company of New Mexico
- San Diego Electric & Gas Co.
- Sierra Pacific Power Co.
- Southern California Edison Co.
- Tucson Gas & Electric Co.
- Utah Power & Light Co.
- Arizona Electric Power Cooperative
- Arizona Power Authority
- Burbank Public Service Department
- City of Colorado Springs
- Colorado–Ute Electric Association, Inc.
- Glendale Public Service Department
- Imperial Irrigation District
- Pacific Power & Light Co.—Wyoming Division
- Pasadena Municipal Power & Light Department
- Plains Electric Generation & Transmission Cooperative, Inc.
- Salt River Project
- Southern Colorado Power Division of Central Telephone & Utilities Corp.

Colorado Systems Coordinating Council (CSCC)
- City of Center, U.S. Bureau of Reclamation
- City of Colorado Springs, Arkansas Valley G & T, Inc.
- City of Estes Park, Colorado–Ute Electric Assn., Inc.

City of Fort Collins
City of Fort Morgan, Tri-State G & T Assn., Inc.
City of Glenwood Springs, Home Light and Power Company
City of Julesburg, Public Service Company of Colorado
City of La Junta
City of Lamar, Southern Colorado Power Division of Central Telephone & Utilities Corp.
City of Las Animas
City of Longmont
City of Loveland
City of Trinidad, Western Colorado Power Co.

	CALPP	COLOPP	NMPP	PNCA	INTER-POOL	SCMG	NWPP	CSCC	RMPP	WEST	WSCC	AMPS	PNUCC
Arizona Electric Power Cooperative										X			
Arizona Power Authority										X	X		
Arizona Public Service Co										X	X		
Arkansas Valley G & T, Inc								X					
Black Hills Power & Light Co									X				
Bonneville Power Administration				X			X				X		
British Columbia Hydro and Power Authority							X				X		
Cheyenne Light, Fuel & Power Co									X				
City of Burbank, California						X				X			
City of Center, Colorado								X					
City of Colorado Springs, Colorado Department of Public Utilities		X						X	X	X			
City of Estes Park, Colorado								X					
City of Forest Grove, Oregon													X
City of Fort Collins, Colorado								X					
City of Fort Morgan, Colorado								X					
City of Glendale, California						X				X			
City of Glenwood Springs, Colorado								X					
City of Julesburg, Colorado								X					
City of La Junta, Colorado								X					
City of Lamar, Colorado								X					
City of Las Animas, Colorado								X					
City of Longmont, Colorado								X					
City of Loveland, Colorado								X					
City of McMinnville, Oregon													X
City of Milton-Freewater, Oregon													X
City of Pasadena, California						X				X			
City of Seattle, Washington Department of Lighting				X			X				X		X
City of Trinidad, Colorado								X					
Colockum Transmission Co., Inc., a subsidiary of Alcoa				X									
Colorado-Ute Electric Association								X	X	X	X		
Community Public Service Co			X										

	CALPP	COLOPP	NMPP	PNCA	INTER-POOL	SCMG	NWPP	CSCC	RMPP	WEST	WSCC	AMPS	PNUCC
Consumers Public Power District (Western Division)									X		X		
Coos-Curry Electric Cooperative, Inc., Coquille, Oregon													X
Department of Water & Power, City of Los Angeles, Calif.						X				X	X		
El Paso Electric Co.			X							X	X		
Eugene, Oregon Water & Power Board				X			X				X		X
Home Light & Power Co.								X					
Idaho Power Co.							X				X	X	
Imperial Irrigation District										X			
Metropolitan Water District											X		
Montana Power Co.				X			X		X		X	X	
Nevada Power Co.										X			
Pacific Power & Light Co.				X	X		X		X	X	X	X	X
Pacific Gas & Electric Co.	X										X		
Plains Electric G & T Coop., Inc.			X							X	X		
Portland General Electric Co.				X	X		X				X		X
Public Service Company of Colorado		X						X	X	X	X		
Public Service Company of New Mexico			X							X	X		
PUD, Central Lincoln; Newport, Oregon													X
PUD, No. 1, Chelan County, Wenatchee, Washington				X			X				X		X
PUD, No. 1, Cowlitz County, Washington				X							X		
PUD, No. 1, Douglas County, Washington				X			X				X		X
PUD, No. 2, Grant County, Washington				X			X				X		X
PUD, Grays Harbor County; Aberdeen, Washington													X
PUD, No. 1, Pend Oreille County, Wash.				X									
PUD, Snohomish County; Everett, Washington													X
Puget Sound Power & Light Co.				X	X		X				X		X
Salt River Project										X	X		
San Diego Gas & Electric Co.	X									X	X		
Sierra Pacific Power Co.										X	X		
Southern California Edison	X									X	X		
Southern Colorado Power Divison of Central Telephone & Utilities		X						X	X	X	X		
Tacoma Public Utilities, Light Division				X			X				X		X
Tri-State G & T Association								X	X		X		
Tucson Gas & Electric										X	X		
USBR—Boulder City													
USBR—CRSP								X	X				
USBR—BPA (Southern Idaho)							X		X				
USBR—MRB Western Division									X				

	CALPP	COLOPP	NMPP	PNCA	INTER-POOL	SCMG	NWPP	CSCC	RMPP	WEST	WSCC	AMPS	PNUCC
USBR—Rio Grande Project			X										
U.S. Army Corps of Engineers				X			X				X		
U.S. Entity				X									
Utah Power & Light Co							X		X	X	X	X	
Washington Water Power Co				X	X		X				X	X	X
Washington Public Power Supply System													X
Benton County PUD													X
Clallam County PUD													X
Ferry County PUD													X
Franklin County PUD													X
Kittitas County PUD													X
Klickitat County PUD													X
West Kootenay Power & Light Co							X				X		
Western Colorado Power								X	X				
Department Water Resources, State of California											X		
Sacramento Municipal Utility District											X		
USBR											X		

Membership of Western Systems Coordinating Council as of January 1, 1969

Arizona Power Authority
Arizona Public Service Company
Bonneville Power Administration
British Columbia Hydro and Power Authority
Bureau of Reclamation
Colorado-Ute Electric Association
Consumers Public Power District—Western System
Department of the Army, North Pacific Division, Corps of Engineers
Department of Water Resources, State of California
El Paso Electric Company
Eugene Water and Power Board
Idaho Power Company
Department of Water and Power, City of Los Angeles
Metropolitan Water District of Southern California
Montana Power Company
Pacific Gas and Electric Company
Pacific Power and Light Company
Plains Electric Generation & Transmission Cooperative, Inc.
Portland General Electric Company
Public Service Company of Colorado
Public Service Company of New Mexico
Public Utility District No. 1 of Chelan County, Washington
Public Utility District No. 1 of Cowlitz County, Washington
Public Utility District No. 1 of Douglas County, Washington
Public Utility District No. 2 of Grant County, Washington
Puget Sound Power and Light Company
Sacramento Municipal Utility District
Salt River Project Agricultural Improvement & Power District
San Diego Gas and Electric Company
City of Seattle Department of Lighting
Sierra Pacific Power Company
Southern California Edison Company
Southern Colorado Power Company, Division of Central Telephone and Utilities, Inc.
Tacoma Public Utilities, Light Division
Tri-State G & T Association
Tucson Gas and Electric Company
Utah Power and Light Company
Washington Water Power Company
West Kootenay Power and Light Company, Ltd.

WESTERN SYSTEMS COORDINATING COUNCIL

ORGANIZATION CHART

December 6, 1968

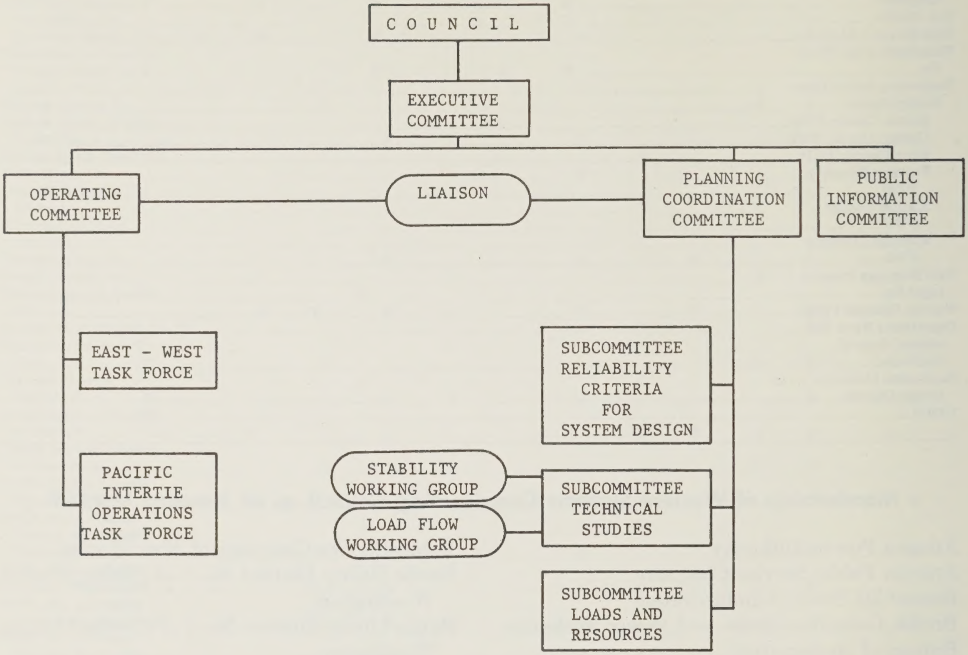


Figure 1

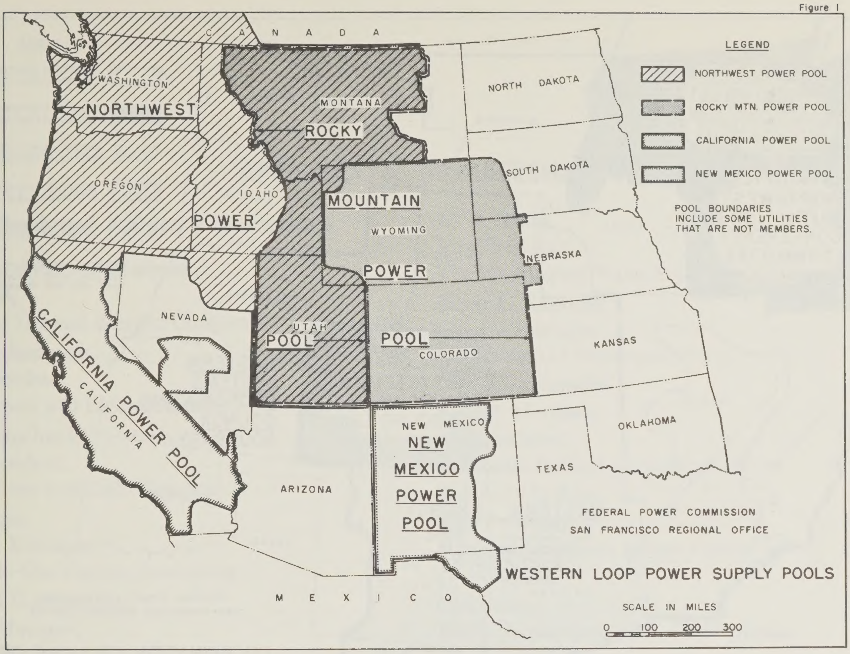


Figure 2

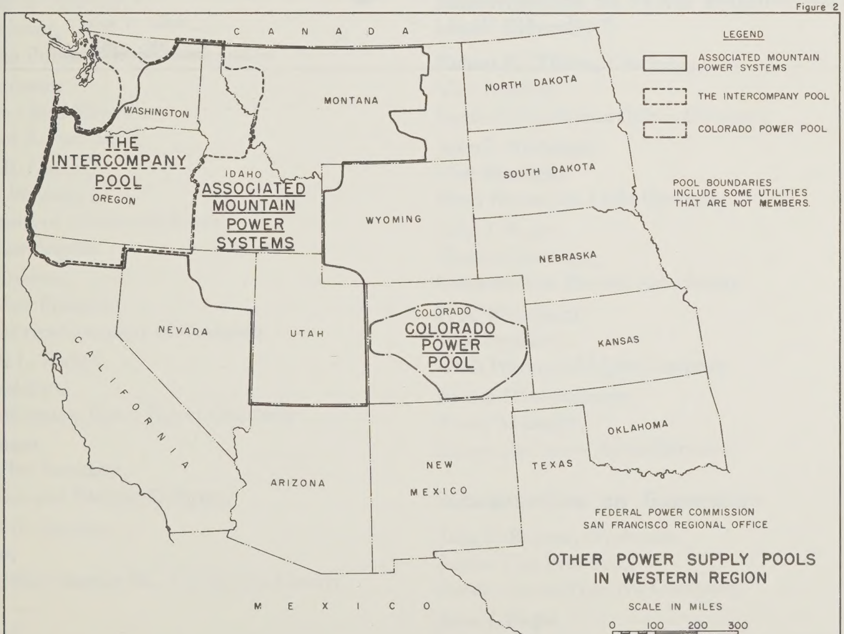
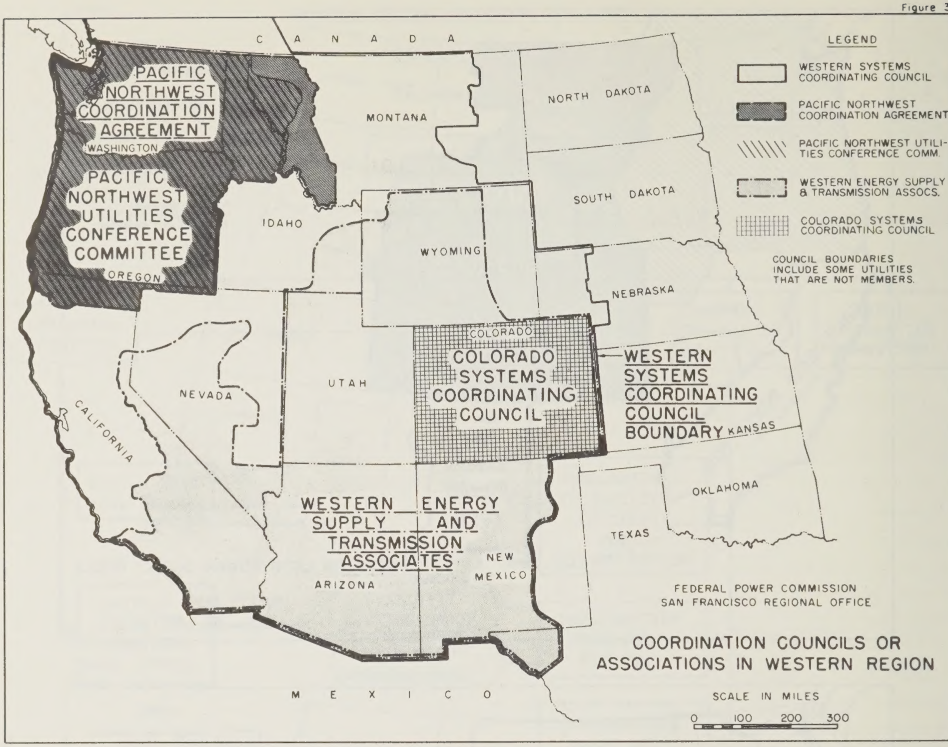


Figure 3



COORDINATION COUNCILS OR ASSOCIATIONS IN WESTERN REGION

APPENDIX 6. MEMBERSHIPS

West Regional Advisory Committee

Frank M. Warren, *Chairman,*
President,
Portland General Electric Company

John F. Anderson,
Vice President,
Utah Power and Light Company

P. A. Blanchard,[1]
Vice President,
Utah Power and Light Company

J. J. Bugas,
General Manager,
Colorado Ute Electric Association

Bernard Goldhammer,
Power Manager,
Bonneville Power Administration

Frederick B. Holoboff,[3]
Commissioner,
California Public Utilities Commission

Emil Lindseth,
Associate Chief Engineer,
Bureau of Reclamation

Samuel B. Nelson,[1]
General Manager,
Department of Water and Power,
City of Los Angeles

L. R. Patterson,
Senior Vice President,
Public Service Company of Colorado

Marshall L. Blair,[2]
Vice President,
The Washington Water Power Company

J. F. Bonner,
Senior Vice President,
Pacific Gas and Electric Company

Howard C. Elmore,
Manager,
Public Utility District No. 1 of Chelan County

[1] Retired.
[2] Deceased.
[3] Term expired.

M. F. Hatch,
Vice President,
The Washington Water Power Company

Edgar L. Kanouse,
General Manager,
Department of Water and Power,
City of Los Angeles

Fred P. Morrissey,
Commissioner,
California Public Utilities Commission

Robert P. O'Brien,
Vice President,
Southern California Edison Company

D. W. Reeves,
Chairman,
Public Service Company of New Mexico

Subcommittee on Power Requirements and Load Diversity

Robert P. O'Brien, *Chairman,*
Vice President,
Southern California Edison Company

John S. Anderson,
Vice President,
Utah Power and Light Company

John J. Bugas,
General Manager,
Colorado Ute Electric Association

P. A. Blanchard,[1]
Vice President,
Utah Power and Light Company

Bernard Goldhammer,
Power Manager,
Bonneville Power Administration

Subcommittee on Generation

John F. Bonner, *Chairman,*
Senior Vice President,
Pacific Gas and Electric Company

John J. Bugas,
General Manager,
Colorado Ute Electric Association

Robert P. O'Brien,
Vice President,
Southern California Edison Company

Task Force on Fuels

Robert P. O'Brien, *Chairman,*
Southern California Edison Company

John J. Bugas,
Colorado Ute Electric Association

William S. Landers,
Public Service Company of Colorado

W. H. Seaman,
Southern California Edison Company

E. J. Lage,[1]
Pacific Gas and Electric Company

Robert B. Lisbakken,
Pacific Power and Light Company

Task Force on Generation

J. D. Worthington, *Chairman,*
Pacific Gas and Electric Company

R. L. Ashenbrenner,
Grant County Public Utility District

S. F. Buese
Southern California Edison Company

Glen E. Bredemeier,
Portland General Electric Company

D. J. Caha,
City of Tacoma, Washington

F. N. Davis,
Utah Power and Light Company

T. R. Heikes,
Idaho Power Company

Robert J. Labrie,
Montana Power Company

Ed C. Metcalf,
Public Utility District No. 1 of Chelan County

W. P. Murphy,
Tucson Gas and Electric Company

A. E. Rhodes,
Public Service Company of New Mexico

Jack T. Stiles,
Pacific Power and Light Company

John A. Gregg,
Public Utility District No. 1 of Douglas County

J. B. Kirkpatrick,
Bureau of Reclamation, Denver

Henderson M. McIntyre,
Bonneville Power Administration

R. P. Mortell,
Puget Sound Power and Light Company

Gregory Prekeges,
The Washington Water Power Company

L. J. Stinson,
Department of Water and Power,
City of Los Angeles

James H. Zornes,
Nevada Power Company

Subcommittee on Transmission

Howard C. Elmore, *Chairman,*
Manager,
Public Utility District No. 1 of Chelan County

Stuart Barker,
Chief Planning Engineer,
The Montana Power Company

Marshall L. Blair,[2]
Vice President,
The Washington Water Power Company

C. R. Canady,
Superintendent of System Operation,
Southern California Edison Company

John Gregg,
Chief Engineer,
Douglas County Public Utility District

B. L. Baugh,
Vice President,
Public Service Company of New Mexico

D. L. Bryner,
Utah Power and Light Company

F. N. Davis,
Manager, Engineering & Construction,
Utah Power and Light Company

P. F. Hargreaves,
Manager, Engineering,
Puget Sound Power and Light Company

E. J. Harrington,
Assistant Chief Engineer,
Bonneville Power Administration

Harvey D. Hunkins,
Assistant Chief, Electrical Branch,
Bureau of Reclamation

R. H. Lemagie,
Power Operations Supervisor,
City of Tacoma, Washington

William J. Martin,
Director, Electric System Planning,
Public Service Company of Colorado

T. A. Phillips,
Vice President and Manager of Engineering Services Group,
Arizona Public Service Company

R. R. Ries,
Power Manager,
Grant County Public Utility District

Conrad L. Ryan,
Chief Electrical Engineer,
Nevada Power Company

Jack T. Stiles,
Vice President,
Pacific Power and Light Company

M. F. Hatch,
Vice President,
The Washington Water Power Company

W. R. Johnson,
Chief Electric Generation and Transmission Engineer,
Pacific Gas and Electric Company

Emil Lindseth,
Bureau of Reclamation

W. McGlothlin,
Superintendent, Electric Engineering and Operations,
Tucson Gas and Electric Company

Gregory Prekeges,
The Washington Water Power Company

D. R. Russell,
Superintendent of Engineering,
Idaho Power Company

William A. Sells,
Engineer of Design and Construction,
Department of Water and Power,
City of Los Angeles

Subcommittee on Coordinated Planning and Development

L. R. Patterson, *Chairman,*
Vice President,
Public Service Company of Colorado

Howard C. Elmore,
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Public Utility District No. 1 of Chelan County

Edgar L. Kanouse,
General Manager,
Department of Water and Power,
City of Los Angeles

Samuel B. Nelson,[1]
General Manager,
Department of Water and Power,
City of Los Angeles

D. W. Reeves,
President,
Public Service Company of New Mexico

Report Drafting Subcommittee

J. F. Bonner, *Chairman,*
Senior Vice President,
Pacific Gas and Electric Company

M. B. Austin,
Regional Engineer,
Federal Power Commission

Howard C. Elmore,
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Public Utility District No. 1 of Chelan County

Robert P. O'Brien,
Vice President,
Southern California Edison Company

P. G. Damask,
Pacific Gas and Electric Company

W. J. Martin,
Director, Electric System Planning,
Public Service Company of Colorado

W. H. Seaman, Fuel Supply Department,
Southern California Edison Company

U.S. GOVERNMENT PRINTING OFFICE: 1970 O—356-240

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NES, DIESELS, AND TOTAL ENERGY SYSTEMS • OTHER FORMS OF GENERATION • COOLING WATER NEEDS AN

D INTERCONNECTION • DISTRIBUTION SYSTEMS • UTILITY PRACTICES AFFECTING RELIABILITY OF SUPPLY

90 • ECONOMIC PROJECTIONS • FINANCING THE GROWTH OF THE ELECTRIC POWER INDUSTRY • REGULAT

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OLLUTION • ESTHETICS AND ENVIRONMENTAL EFFECTS • TRANSMISSION AND INTERCONNECTION • DISTR

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OTAL ENERGY SYSTEMS • OTHER FORMS OF GENERATION • COOLING WATER NEEDS AND SUPPLIES • AIR

ON • DISTRIBUTION SYSTEMS • UTILITY PRACTICES AFFECTING RELIABILITY OF SUPPLY • PROBLEMS IN T